AXL 2000 ANNUAL REPORT

Leading the way

ANDERSON
EXPLORATION LTD.

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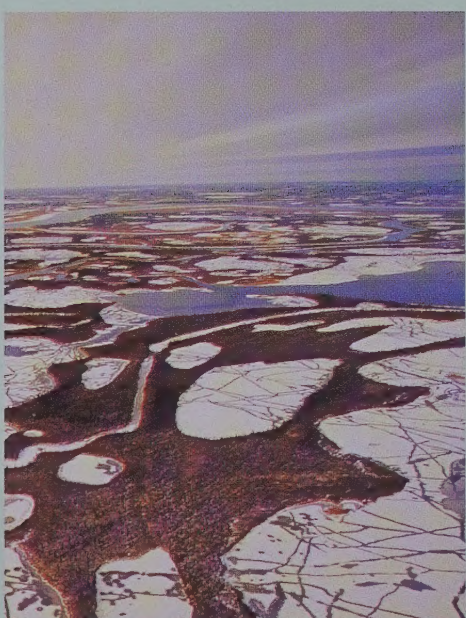


ABOUT THE COMPANY Anderson Exploration Ltd. is a senior Canadian oil and gas producer based in Calgary, Alberta. The Company evolved from a program of oil and gas exploration, acquisition and development commenced by Mr. J.C. Anderson in 1968. Anderson Exploration became a public company in 1988 and has a September 30 year end. The common shares of the Company are widely held and trade on The Toronto Stock Exchange under the symbol AXL. Trading volumes reflect excellent liquidity with an average of 594,400 common shares per trading day representing 118 percent turnover in fiscal 2000. Anderson Exploration has a large oil and gas reserve base and operates approximately 80 percent of its production. The Company operates exclusively in western and northern Canada and is heavily leveraged to natural gas with 66 percent of its reserves and 72 percent of its production made up of natural gas.

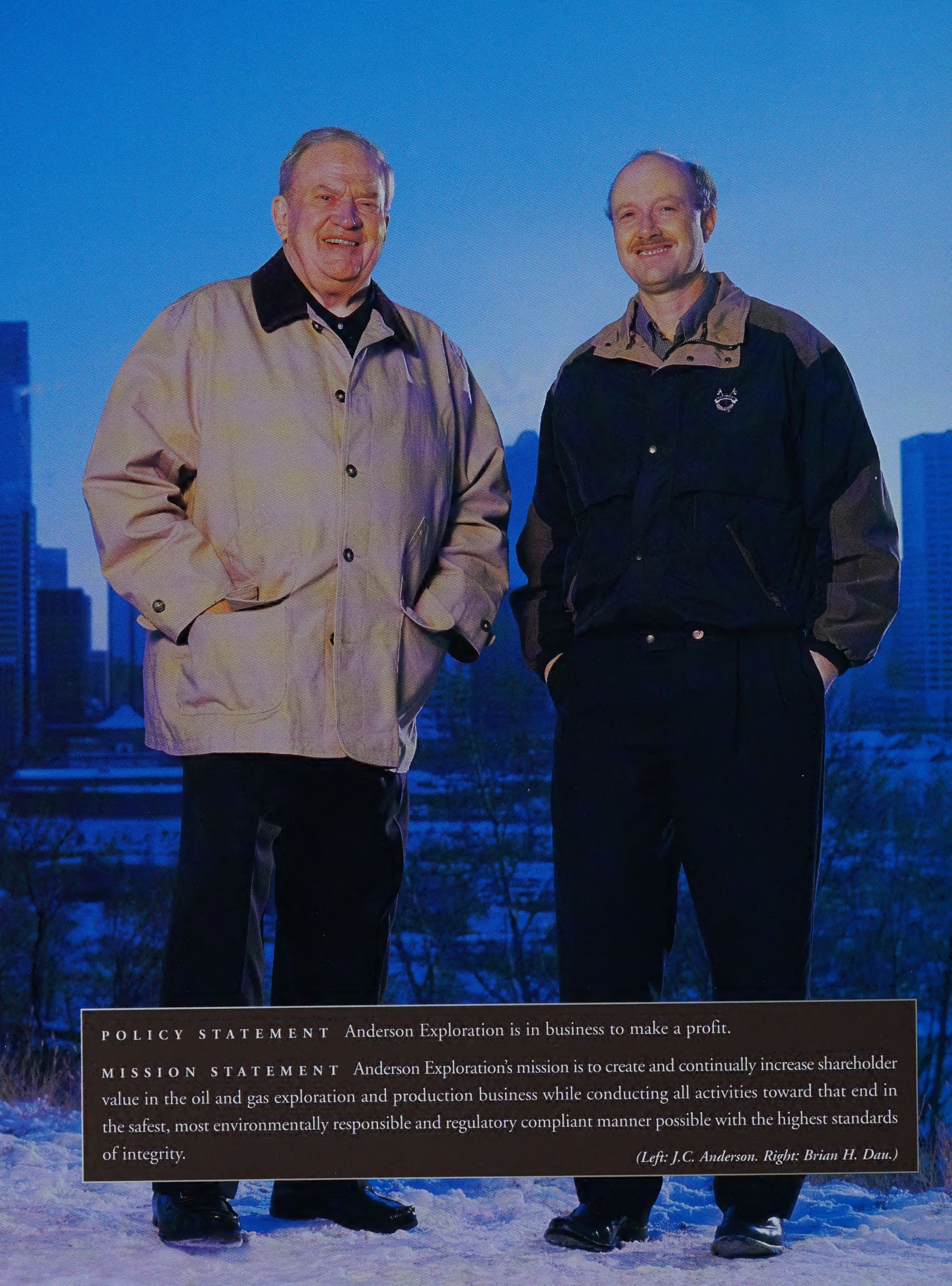
ABOUT THE COVER Anderson Exploration is becoming a leader in exploration in Canada's far north. The photograph shows terrain in the Mackenzie Delta region of the Northwest Territories in early October as lakes are beginning to freeze over. In fiscal 2000, Anderson Exploration became the largest holder of exploration acreage in this area and is now well positioned to commence a long term exploration program for major reserves North of 60°.

ANNUAL AND SPECIAL MEETING The Annual and Special Meeting of Shareholders will be held on February 13, 2001 at 3:00 p.m. at the Westin Hotel, Calgary, Alberta.

HIGHLIGHTS

FINANCIAL (in millions, except per share amounts)	2000	1999	% Change
Total oil and gas revenue	$ 1,417.1	$ 770.9	84
Oil and gas revenue, net of royalties	$ 1,125.3	$ 645.0	74
Cash flow from operations	$ 801.3	$ 395.6	103
Per common share (basic)	$ 6.29	$ 3.19	97
Earnings	$ 313.5	$ 70.4	345
Per common share (basic)	$ 2.46	$ 0.57	332
Average shares outstanding	127.4	124.1	3
Net oil and gas capital expenditures	$ 669.4	$ 283.8	136
Corporate acquisition	$ 1,000.7	$ –	–
Long term debt	$ 1,126.9	$ 545.2	107
Shareholders' equity	$ 1,563.5	$ 1,135.8	38

OPERATING			
Daily sales			
Natural gas (Mmcfd)	626	568	10
Light/medium crude oil (Bpd)	23,672	22,840	4
Heavy crude oil (Bpd)	5,354	2,725	96
Total crude oil (Bpd)	29,026	25,565	14
NGL (Bpd)	11,379	8,020	42
Total liquids (Bpd)	40,405	33,585	20
Average prices			
Natural gas ($/Mcf)	$ 3.83	$ 2.48	54
Light/medium crude oil ($/Bbl)	$ 39.48	$ 21.94	80
Heavy crude oil ($/Bbl)	$ 28.98	$ 14.68	97
Total crude oil ($/Bbl)	$ 37.55	$ 21.17	77
NGL ($/Bbl)	$ 29.06	$ 15.82	84
Total liquids ($/Bbl)	$ 35.16	$ 19.89	77
Reserves			
Natural gas (Bcf)			
Proven	2,231	1,812	23
Proven plus probable	3,239	2,699	20
Crude oil and NGL (Mbbls)			
Proven	190,877	146,042	31
Proven plus probable	273,903	221,672	24
Undeveloped land (thousands of acres)			
Western provinces			
Gross	5,151	3,968	30
Net	3,849	3,081	25
Frontier			
Gross	4,303	1,671	158
Net	2,012	353	470
Wells drilled for oil and gas (gross wells)			
Gas wells	277	179	55
Oil wells	234	46	409
Dry holes	119	48	148
Total	630	273	131
Employees			
Calgary	467	410	14
Field	387	352	10
Total	854	762	12



POLICY STATEMENT Anderson Exploration is in business to make a profit.

MISSION STATEMENT Anderson Exploration's mission is to create and continually increase shareholder value in the oil and gas exploration and production business while conducting all activities toward that end in the safest, most environmentally responsible and regulatory compliant manner possible with the highest standards of integrity.

(Left: J.C. Anderson. Right: Brian H. Dau.)

Leading the way in natural gas

KEY ACHIEVEMENTS IN FISCAL 2000

- Achieved record levels of production, cash flow and earnings
- Became the largest holder of exploration acreage in the Mackenzie Delta – Beaufort Sea
- Completed the strategic purchase of Ulster Petroleums Ltd.
- Disposed of a non-strategic investment in Federated Pipe Lines Ltd.
- Ramped up heavy oil production to take advantage of current prices
- Issued $175 million in medium term notes under first public debt offering
- Instituted a normal course issuer bid and purchased 3.3 million shares prior to its expiry
- Maintained a strong balance sheet, ending the year with a debt to cash flow ratio of 1.4

Fiscal 2000 was a record year for Anderson Exploration. Cash flow in total and on a per share basis was double the previous record year of 1999. Earnings and earnings per share exceeded the previous record year of 1997 by about 3.5 times. As well, the highest production levels in the Company's history were achieved and prices for our commodities improved substantially year over year. As predicted, natural gas prices increased throughout the year to finish at record levels. The Company made significant progress on its Strategic Plan, completing several transactions during the year. Notable were the acquisition of Ulster Petroleums Ltd., the disposition of Federated Pipe Lines Ltd. and, as a first step toward becoming more active in exploration North of 60°, the execution of a significant exploratory land acquisition program in the area.

Cash flow increased 103 percent and earnings were up 345 percent over fiscal 1999. Capital spending, not including the Ulster acquisition, increased by 136 percent over 1999 but represented only 84 percent of cash flow. As a result of our strong balance sheet, the $1.0 billion Ulster acquisition was 90 percent debt financed. Since the acquisition

of Ulster in May, we have reduced our debt using cash flow and the proceeds from the sale of Federated Pipe Lines. At year end, long term debt was 1.4 times trailing cash flow. Our finding and development costs were substantially higher in 2000 than in 1999 due, in part, to significant pre-investments in land and seismic for future exploration and increasing cost pressures on the service side of the business. Given our momentum and the current and projected outlook for commodity prices, in particular natural gas, there is every reason to expect that 2001 will bring new records for production, cash flow and earnings by substantial margins.

YEAR 2000 IN REVIEW Cash flow from operations more than doubled to $801 million or $6.29 per share in 2000 versus $396 million or $3.19 per share in 1999. Earnings increased to $314 million or $2.46 per share from $70 million or $0.57 per share in 1999. Included in earnings in 2000 is a one-time gain of $64 million on the sale of Federated Pipe Lines.

Natural gas prices increased 54 percent to average $3.83 per thousand cubic feet in 2000 versus $2.48 per thousand cubic feet in 1999. Natural gas prices increased steadily throughout the year with the Company's average price during September, the last month of the fiscal year, reaching $5.38 per thousand cubic feet. These are the highest gas prices the Company has seen in its 32 year history. Gas sales volumes increased to 626 million cubic feet per day from 568 million cubic feet per day in 1999, including an annualized 42 million cubic feet per day from the Ulster properties acquired on May 17. We expected oil prices to stay strong during the year but we did not expect prices to reach Gulf war levels. Our average wellhead price in 2000 was $37.55 per barrel versus $21.17 per barrel in 1999, a 77 percent increase. Oil sales increased 14 percent to 29,026 barrels per day from 25,565 barrels per day last year. The heavy oil contribution increased 96 percent to 5,354 barrels per day from 2,725 barrels per day in 1999. NGL sales volumes increased 42 percent during the year to 11,379 barrels per day. NGL prices increased by 84 percent during the year to average $29.06 per barrel.

Net oil and gas capital expenditures were $669 million in fiscal 2000, excluding the Ulster acquisition, representing 84 percent of cash flow from operations. The Ulster acquisition resulted in the expenditure of another $1.0 billion. The Company replaced 316 percent of its production with proven reserves. The Company's proven finding and development costs for the year, net of revisions, were $9.84 per barrel of oil equivalent. Prior to revisions, the Company's finding and development costs were $8.95 per barrel of oil equivalent. Negative revisions of three percent of the total proven reserve base were taken this year due to performance issues with certain properties and the adoption of higher proven and probable reserve confidence levels in anticipation of more stringent generally accepted reserve definitions for the industry. Finding and development costs were higher this year due to significant land and seismic expenditures made to set up future exploration plays, higher costs of doing business and, generally, a modest year in terms of exploration discoveries. Notwithstanding these costs, we are enthusiastic about the direction of the current exploration program and anticipate that finding and development costs will be lower in the coming year. The Company

began the year with a debt to trailing cash flow ratio of 1.4 years and ended the year with the same ratio. During its Normal Course Issuer Bid instituted during the year, the Company purchased 3.3 million of its common shares at an average price of $19.93 per share before the expiry of the bid on November 30, 2000.

NORTH OF 60° Looking to the future and the need for major new gas supplies in North America, Anderson Exploration has assembled an impressive exploratory land position North of 60°. Exploration acreage totalling 1.9 million gross acres or 1.3 million net acres in the Mackenzie Delta and shallow water Beaufort Sea area were acquired in federal and Inuvialuit land sales making the Company the largest exploration acreage holder in this region. In addition, the Company acquired a 100 percent interest in two Exploration Permits on 198,000 acres in the Eagle Plain area of the Yukon Territory and a 100 percent interest in a 318,000 acre Exploration Licence in the Central Mackenzie Valley in the Northwest Territories. Some exploratory work was conducted in 2000 and additional work will be conducted in 2001.

PEOPLE Fiscal 2000 brought changes to the management team at Anderson Exploration. Kevin Stashin was promoted to Vice President, Operations, Phil Harvey was promoted to Vice President, Exploitation and David Spyker was promoted to Manager, Business Development. In November 2000, Brian Dau was promoted to President and has been proposed as a nominee for election to the Board of Directors by the shareholders at the next annual meeting to be held in February 2001.

FISCAL 2001 CAPITAL BUDGET The capital expenditure budget for fiscal 2001 is $790 million. Exploration and land expenditures represent over 50 percent of the budget. We have allocated $49 million in capital spending to the program in the Mackenzie Delta including participation in our first well in the area. The budget contemplates drilling 13 percent of our exploratory wells to a depth of more than 2,800 metres. These deeper wells represent 25 percent of the total exploratory drilling capital. Approximately 78 percent of expenditures will be directed toward gas programs. The budget will be funded by cash flow. Cash flow should well exceed capital expenditures and surplus cash will be used to reduce debt, finance acquisitions or repurchase common shares pursuant to a newly approved Normal Course Issuer Bid.

THE NATURAL GAS STORY This Company has always had a bias toward natural gas. As a result, Anderson Exploration is the senior Canadian producer most leveraged to natural gas. In 2000, natural gas accounted for 72 percent of our product sales and 66 percent of our year end remaining proven reserves on a barrel equivalent basis. Natural gas sales provided 62 percent of our total revenue before royalties. We have been expounding the merits and pitfalls of the natural gas business for many years. We have consistently predicted economic improvements to Canadian producers as a result of careful examination of the fundamentals of the business in North America from exploration, production and marketing perspectives.

To quote from past Annual Reports:

1988 "Canada currently supplies approximately six percent of the gas requirements of the United States. The prospects for increased penetration into this market are excellent."

1990 "Gas must gain a bigger share of total energy consumption."

1992 "The fundamentals are in place for the infamous gas bubble to deflate. This leads to the conclusion that natural gas prices have bottomed and there will be a gradual upward trend."

1997 "We believe we are now on the cusp of enjoying increased gas prices for a number of years."

1998 "The basic fundamentals of the gas business in North America remain essentially the same as in 1992. … All of these fundamentals point to increasing gas prices for Canadian producers."

The detail associated with these quotes is in the record. Now that we are enjoying the predicted upward trend in natural gas prices, we are being asked if this natural gas price environment is sustainable. Our answer is an unqualified yes for the following reasons:

- Overall North American supply, in the form of production capability, and demand are currently in delicate balance.
- Demand continues to increase in the United States at a rate greater than the increase in production capability.
- We now have sufficient and, in fact, excess export pipeline capacity from western Canada to prevent gas from backing up in the region in quantities in excess of local demand, depressing prices.
- The gas reserve life in Canada has been reduced to a level roughly equivalent to that in the United States resulting in industry producing at maximum capacity.
- Canada now has a high decline rate from current production, equivalent to that of the United States.
- Most of the easy opportunities to ramp up production from the existing continental reserve base have been exhausted.
- Generally, new supply sources will be needed to replace production decline and to provide production increases.
- Year over year percentage increases in gas receipts delivered to pipeline systems in western Canada have declined from about 10 percent seven years ago to zero in the past year in spite of dramatic increases in year over year new gas well connections during the period.
- During the gas storage fill season from last April to November, the industry was unable to fill storage in the U.S. and Canada to the desired levels.

The bottom line is that a supply side problem has developed as we predicted. All of the above point to sustainability of the present gas price scenario well into the future and should serve to overcome any high price driven reduction in demand.

OUTLOOK We are entering fiscal 2001 in a very strong commodity price environment. Natural gas prices should prevail at high levels throughout 2001 and well beyond. The Company is well positioned to capitalize on these prices with over 70 percent of its current production made up of natural gas. The Company is currently unhedged with approximately 84 percent of its gas sales portfolio priced in western Canada. Some weakness in crude oil and NGL prices from current levels is possible, but we expect liquids prices to remain at very acceptable levels throughout 2001.

We are entering our busiest year from an exploration point of view in western Canada. We are excited about kicking off our multi-year exploration effort North of 60° and look forward to positive results there as time goes on, hopefully leading to development of major gas resources to serve the inevitable pipeline to hungry southern markets. Our balance sheet, even after debt financing most of the Ulster acquisition, remains strong and we will continue to evaluate opportunities to promote prudent growth in shareholder value. Given continued strength in commodity prices we will experience another record year for production, cash flow and earnings in fiscal 2001. Our prospects have never looked better.

We take this opportunity to thank our employees for their dedication and exceptional performance in 2000. We also appreciate the continuing support of our shareholders in the current and coming years.

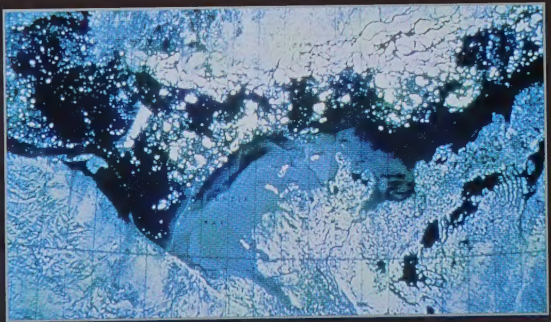
J.C. Anderson

J.C. Anderson
Chairman & Chief Executive Officer

Brian H. Dau
President & Chief Operating Officer

January 3, 2001

As a result of Anderson Exploration's significant exploration land acquisition program North of 60°, the Company now holds 1.9 million gross acres (1.3 million net acres) in the Mackenzie Delta and shallow water Beaufort Sea area. The satellite photo of the region shows the ice receding from the shoreline in June. The map is a portion of the same area showing the Company's significant acreage in the region.



Leading the way in northern exploration

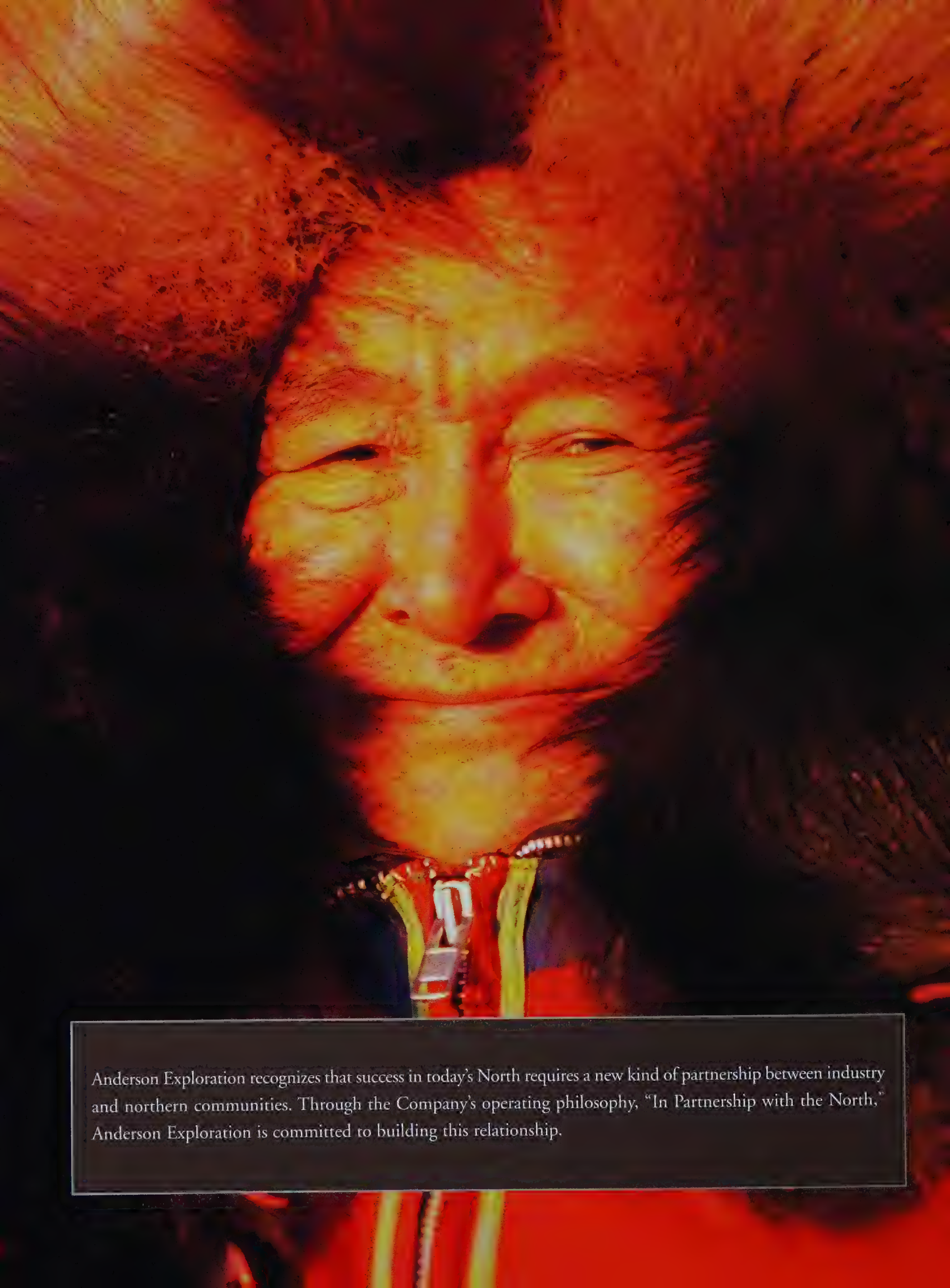
North of 60°

A STRATEGIC CORPORATE DECISION In the summer of 1999, Anderson Exploration made a strategic decision to become more active in exploration in the Canadian frontier north of the 60th parallel. This direction was taken for several reasons, namely:

- The North American natural gas market fundamentals were unfolding as predicted, with increasing demand and diminishing current supply creating the need for large new sources of gas supply in the future;
- Natural gas prices were increasing and were predicted to reach levels that would justify the economics of a successful long term program North of 60°;
- The region holds enormous hydrocarbon potential, particularly in the Mackenzie Delta and Beaufort Sea areas with their already discovered resources;
- Anderson Exploration has several years of successful operating experience in the north with the Kotaneelee gas field in the Yukon;
- The Company has participated in successful exploration in the Liard Basin in the southern Northwest Territories; and
- It is a play off the interests already held by the Company North of 60° as a result of the Columbia Gas and Home Oil acquisitions in 1992 and 1995.

PROGRESS TO DATE In September 1999, the first Call for Bids in many years was conducted by the federal government for acreage in the Mackenzie Delta. Anderson Exploration was successful in obtaining a 40 percent interest in two of the four onshore Exploration Licences offered. At the next Call for Bids, the Company acquired a 40 percent interest in two onshore Exploration Licences in the Mackenzie Delta and a 100 percent interest in four offshore Exploration Licences in the shallow water Beaufort Sea. The Company also acquired a 50 percent interest as operator in two Concession Agreements in a freehold tender process conducted by the Inuvialuit. As a result, Anderson Exploration is now the largest holder of Exploration Licence and Concession acreage in the Mackenzie Delta and shallow water Beaufort Sea area with a working interest in 48 percent of the total acreage disposed to the industry and a 33 percent ownership on a net basis. The Company's land holdings are significant as this is essentially all of the exploration acreage available in the area for the next five to nine years. As well, the Company acquired a 100 percent interest in a large Exploration Licence in the Central Mackenzie Valley near Norman Wells and in two Exploration Permits in the Eagle Plain area on the Dempster Highway in the Yukon.

Anderson Exploration is now well positioned to commence a long term exploration program for major reserves North of 60°. The Company is carrying out its exploration with a fully integrated team of geologists, geophysicists, engineers and geoscience specialists. Last winter in the Mackenzie Delta, 68 square miles of 3-D and 34 miles of 2-D seismic were acquired. This winter, the first well will be drilled on that 3-D survey with Petro-Canada operating. In addition, onshore plans are for 213 square miles of 3-D seismic operated by Petro-Canada and 94 square miles of 3-D and 38 miles of 2-D seismic operated by Anderson Exploration. In the shallow water Beaufort Sea, the Company is planning to operate at least 300 square miles of marine 3-D seismic in the summers of 2001 and 2002. The Company anticipates its first operated drilling in the Mackenzie Delta in the winter of 2002. At Eagle Plain in the Yukon, a 172 mile 2-D seismic program is contemplated in 2001.



Anderson Exploration recognizes that success in today's North requires a new kind of partnership between industry and northern communities. Through the Company's operating philosophy, "In Partnership with the North," Anderson Exploration is committed to building this relationship.

THE NEW NORTH In the late 1970s, after a period of intense exploration activity, the federal government placed a moratorium on the issuance of additional licences for exploration rights on federal lands. Additionally, the 1977 Berger Commission Report effectively placed a moratorium on pipeline construction North of 60°. A major objective of both of these initiatives was to permit the settlement of land claims by Aboriginal and First Nations peoples in the North. The moratoriums have largely served their purpose since most of these groups are negotiating or have completed the settlement of their claims. The new socio-economic environment of the North now looks to balance traditional lifestyles with a modern economy. Attitudes have changed from the "not ready yet" stance of the 1980s and early 1990s to a shared vision of sustainable development. Voices in the community who once objected to industrial activity are now strong proponents of development. According to the Honourable Joseph Handley, Minister of Resources, Wildlife and Economic Development, Government of the Northwest Territories, northern communities are now looking for "a prosperous and diverse economy built on the strengths of our people and the wise use and conscientious protection of our natural resources – one which attracts investment and provides communities and individuals with opportunities to be productive and self-reliant."

"Our children will inherit a secure future which provides a healthy environment and which balances traditional lifestyles with a modern economy."

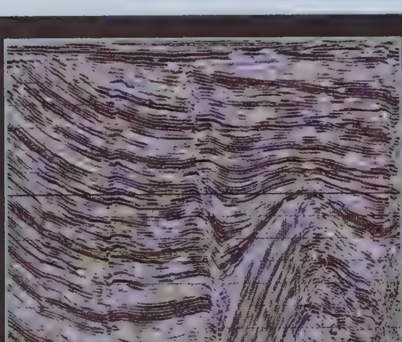
The Honourable Joseph Handley, Minister of Resources, Wildlife and Economic Development, Government of the Northwest Territories

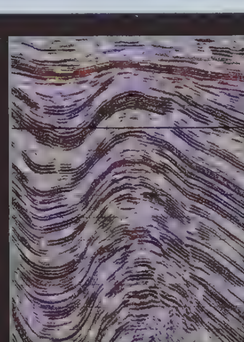
Anderson Exploration recognizes that success in today's North requires a new kind of partnership between industry and northern communities, a partnership based on trust, communication and cooperation. In conducting its operations, the Company is committed to working with northern communities to preserve and respect the cultural identity and values of northern people, to maximize local economic benefits and build local business capacity, and to protect and preserve wildlife, the environment and biological productivity.

Geologically, lands extending North of 60° from the Alberta-British Columbia border to the Beaufort Sea are a continuation of the oil and gas rich Western Canada Sedimentary Basin. However, in comparison they are lightly explored, and contain significant resource potential to be discovered and developed.

PRIOR EXPLORATION Exploration began North of 60° in the 1920s with the drilling of wells along the Mackenzie River to test the source of oil seeps near what would become the giant Norman Wells oilfield. In World War II, efforts to utilize this oil saw the drilling of 86 wells in this area by 1945. With the depletion of the major oil fields in Alberta and Saskatchewan, Norman Wells remains Canada's second largest conventional oil field in terms of daily production. Oil and gas exploration became more widespread in Canada's North during the late 1950s and early 1960s. Notable successes included the discovery of Pointed Mountain in the southwest corner of the Northwest Territories and Kotaneelee in the southeast corner of the Yukon. Both fields produce gas from deep fractured Devonian carbonates in a mountainous thrust belt setting. Kotaneelee is operated by Anderson Exploration.

Exploration in the Mackenzie Delta began in earnest in 1969 and continued through the 1970s and 1980s. In the late 1970s, exploration moved offshore into the Beaufort Sea and continued through the 1980s with the introduction of the Petroleum Incentive Program (PIP) grants. Exploration ground to a halt in the late 1980s with the collapse of oil and gas prices, the elimination of PIP grants and a moratorium placed on the issuance of any additional land rights pending settlement of land claims issues. In the Mackenzie Delta and Beaufort Sea, 249 wells have been drilled with 183 classified as exploration wells. Fifty-three oil and gas accumulations were discovered with four of the gas fields credited with in excess of one trillion cubic feet and 13 credited with between 100 and 500 billion cubic feet. The past discovery record projects excellent future reserve potential, particularly as new 3-D seismic technology is now available. The Geological Survey of Canada estimates the discovery of nine trillion cubic feet of gas to date with an ultimate potential of 65 trillion cubic feet and 1.7 billion barrels of oil discovered out of a potential of 7.1 billion barrels.



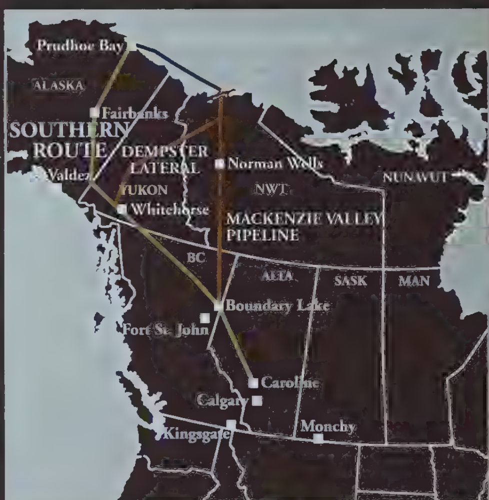


Seismic data illustrating two of the prospective structures located on recently acquired offshore Exploration Licences. These structures are close to previous discoveries made near Anderson Exploration lands in the Beaufort Sea.

Seismic data courtesy of GSI

GEOLOGY The North of 60° exploration areas are generally characterized by geological settings distinctly different from those to the south. In the Mackenzie Delta and shallow water Beaufort Sea area, a 65 million year old, thick Tertiary Delta complex was deposited over an earlier rift basin of Cretaceous age. The geology is complex with most of the hydrocarbons found to date trapped in faulted anticlinal structures. Cretaceous Kamik sands, deposited in braid plain and fluvial environments during the Cretaceous rift event, are effectively charged with gas at the Parsons Lake field containing resource potential of 1.8 trillion cubic feet. Approximately three quarters of Anderson Exploration's onshore acreage is on-trend to this accumulation. The younger Tertiary Delta complex is prospective on about half of the Anderson Exploration acreage. The most prospective reservoirs of the deltaic sands are contained within the

Kugmallit, Richards and Taglu sequences. The Taglu hosts a field by the same name with a resource potential of over three trillion cubic feet of gas. Wells penetrating these Tertiary sands often have over 60 metres of pay distributed over five or six zones, many testing gas at very high flow rates. In the Mackenzie Corridor, Eagle Plain and Liard basins, Cambrian and Devonian aged structures are overprinted by Laramide folding and thrusting. Reservoirs in these structures range upward from Cambrian sands and fractured Middle Devonian carbonates to Mississippian sandstones.

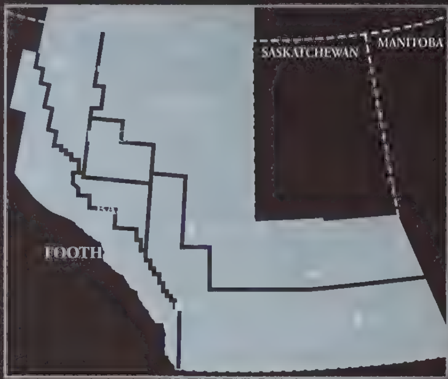


There are a number of potential routes being considered to move northern gas to markets. While economics will play a large part in choosing between various transportation options, the decision will also be influenced by political concerns, regulatory and fiscal regimes, environmental impacts and Aboriginal and First Nations issues.

PRODUCT TRANSPORTATION The building of a gas pipeline to deliver gas to southern markets from the North Slope of Alaska has been under consideration for nearly 30 years. Any such pipeline will have to cross Canadian soil and will likely move gas out of Canada's North as well. With northern gas volumes required to meet growing demand in Canada and the United States, construction of one or more pipelines from the North Slope, the Beaufort Sea and the Mackenzie Delta to southern markets is inevitable. Two major routes which involve Alaska North Slope gas are presently being considered. The northern route would run offshore in the Beaufort Sea from Prudhoe Bay to the Mackenzie Delta and then up the Mackenzie River Valley to tie into existing pipeline infrastructure in Alberta. The southern route would parallel the existing trans-Alaska oil pipeline, then roughly parallel the Alaska Highway through the Yukon and British Columbia to tie into existing infrastructure in Alberta. A third very practical option is a line from the Delta up the Mackenzie River Valley to exclusively carry Canadian gas. There are sufficient reserves and future potential in the area to justify such a line. For oil and natural gas liquids transportation out of the Mackenzie Delta, the line already in place to Norman Wells, which is about halfway from the northern Alberta border to the Delta, could be extended and expanded. Alternatively, if the northern route is chosen for the gas pipeline, a parallel oil line could move liquids from the Mackenzie Delta to Prudhoe Bay for transport to Valdez on the existing trans-Alaska oil pipeline.

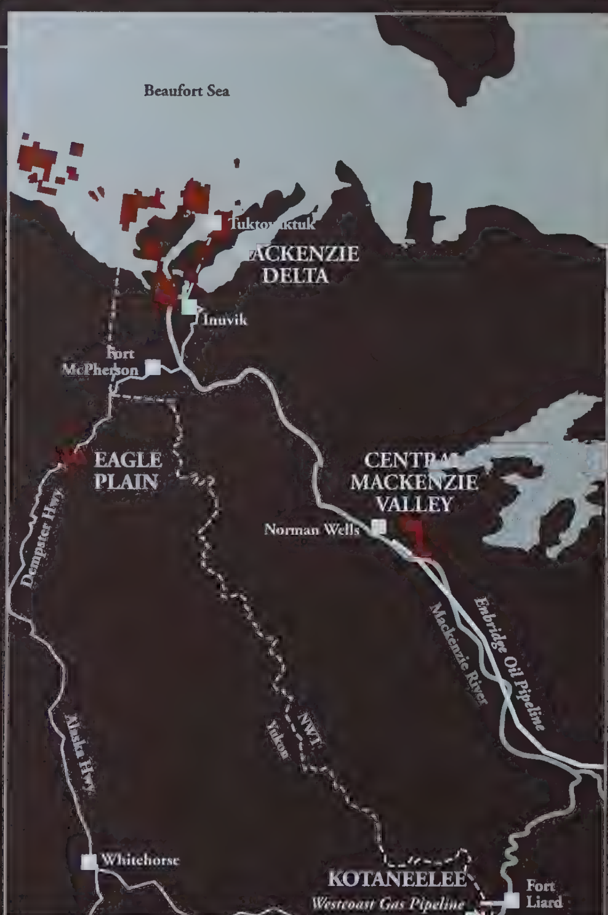
The Company's diverse portfolio of northern properties exposes it to all of the pipeline scenarios now being proposed for northern gas transmission. With its land positions and work proposals, Anderson Exploration is leading the way to realize the vast potential of the area, in partnership with the North.

Anderson Exploration's North of 60° land holdings provide significant reserve and production potential to be developed over the long term. The Company's portfolio of properties in western Canada provides substantial exploration and development opportunities over the intermediate term. The capital budget for fiscal 2001 is \$790 million, including approximately \$49 million for seismic activity and drilling North of 60° in the Mackenzie Delta and Eagle Plain areas.



Anderson Exploration's operations are divided into seven main regions of exploration and development activity based on geology and geography. These regions stretch from the Beaufort Sea to Manitoba. They present the Company with the opportunity to participate in most types of geological plays and produce all types of hydrocarbons.

The Company's focus in 2001 will be on exploration in the Frontier, the Deep Basin, the less explored areas of the Foothills and central Plains, and in northeast British Columbia. Development expenditures will centre on gas pools in the Deep Basin, the Peace River Arch, the Plains and northeast British Columbia. Conventional oil development will take place in the central Plains while heavy oil development will continue in the northern Plains.



FRONTIER

2000 Activity and Results

- Sales – 11 Mmcfd
- Acquired 1,643,500 net acres of Crown and Inuvialuit land
- Hold 2,011,500 net undeveloped acres in region
- Participated in Fort Liard M-25 well with a 4.1 percent interest
- Fort Liard K-29 commenced production in April 2000 at gross raw production of 75 Mmcfd (2.3 Mmcfd net sales)
- Installed field compression at Kotaneelee
- Participated in Petro-Canada operated 3-D seismic survey in the Mackenzie Delta

2001 Planned Activity

- Fort Liard M-25 commenced production in November 2000 with gross raw production of 40 Mmcfd (1 Mmcfd net sales)
- Participate with Petro-Canada drilling a well in the Mackenzie Delta
- Major 3-D seismic programs in the Mackenzie Delta

FOOTHILLS

2000 Activity and Results

- Sales – 40 Mmcfd and 933 Bpd
- Acquired 87,800 net acres of Crown land and Ulster acquisition added 20,200 net acres
- Hold 232,300 net undeveloped acres in region
- Drilled 18 gross (8 net) wells, resulting in 17 gas wells and 1 dry hole
- Farmed in on 46,700 acre block at Narraway
- Four new wells at Narraway tested at rates from 2 Mmcfd to 18 Mmcfd from multiple reservoirs (working interests range from 37.5 to 100 percent)
- Commenced a 10 Mmcfd expansion of the Findley facility increasing production to 32 Mmcfd (12 Mmcfd net)
- Participated in the construction of a 25 mile, 8 inch gas pipeline at Narraway
- 3-D seismic program completed at Findley
- At Bighorn, 7 new wells tested at rates from 5.1 Mmcfd to 11.9 Mmcfd (1.5 Mmcfd to 3 Mmcfd net)

2001 Planned Activity

- Drill 22 gross (12 net) exploration wells and 8 gross (4 net) development wells
- New exploration drilling at Sikanni, Narraway, Findley and Bighorn
- Participate in 820 square miles of 3-D seismic
- Participate in construction of a 31.5 mile sour gas gathering system at Bighorn
- Commence production of 21 Mmcfd of sweet gas at Narraway
- Start work on a sour gas pipeline and processing options for Narraway

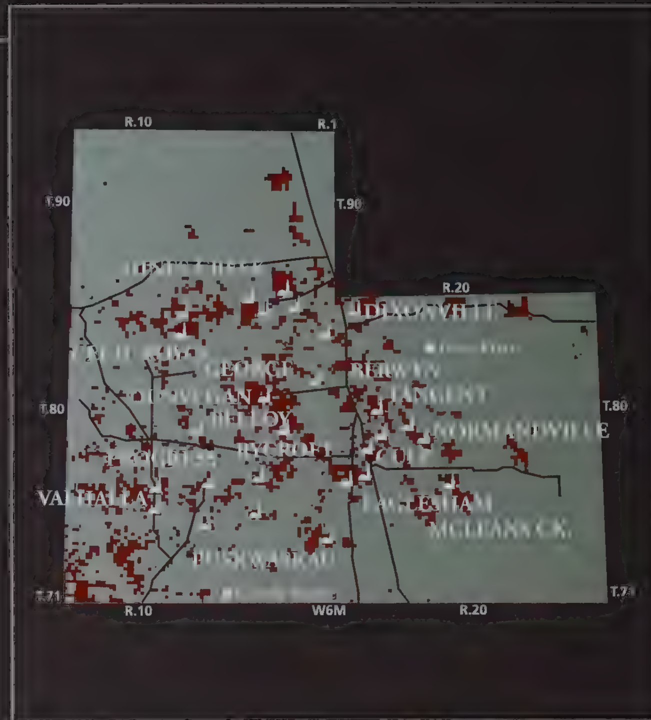
DEEP BASIN

2000 Activity and Results

- Sales – 48 Mmcfd and 2,273 Bpd
- Acquired 74,600 net acres of Crown land and Ulster acquisition added 289,100 net acres
- Hold 490,900 net undeveloped acres in region
- Drilled 52 gross (23 net) wells, resulting in 46 gas wells, 2 oil wells and 4 dry holes
- Acquired Ulster assets with significant land, reserves, production and infrastructure
- Added incremental production of 5 Mmcfd in Bilbo, 4 Mmcfd in Karr and 3 Mmcfd in Wapiti, exclusive of Ulster acquisition
- Tested a significant gas find in the Pinto area

2001 Planned Activity

- Drill 62 gross (36 net) exploration wells and 41 gross (16 net) development wells
- Participate in West Simonette pipeline to expand Wapiti area sour gas production base



NE BRITISH COLUMBIA

2000 Activity and Results

- Sales – 105 Mmcfd and 6,432 Bpd
- Acquired 173,000 net acres of Crown land and Ulster acquisition added 3,100 net acres of undeveloped land
- Hold 727,500 net undeveloped acres in region
- Drilled 79 gross (61 net) wells, resulting in 42 gas wells, 8 oil wells and 29 dry holes
- Drilling at Tooga and Wargen added 13 Mmcfd

2001 Planned Activity

- Drill 53 gross (48 net) exploration wells and 37 gross (18 net) development wells
- Drill 33 wells at Tooga/Peggo/Pesh for Jean Marie
- Drill 23 wells at Birley/Wargen and expand compressor stations

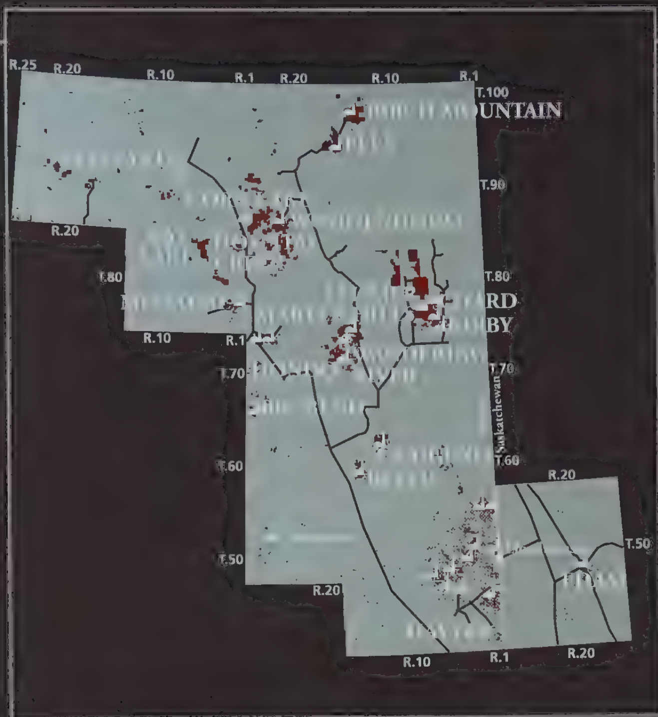
PEACE RIVER ARCH

2000 Activity and Results

- Sales – 196 Mmcfd and 8,145 Bpd
- Acquired 57,700 net acres of Crown land and Ulster acquisition added 104,200 net acres
- Hold 782,800 net undeveloped acres in region at year end
- Drilled 74 gross (48 net) wells, resulting in 42 gas wells, 3 oil wells, 23 dry holes and 6 service wells
- Constructed West Culp sour gas plant
- Constructed Mcleans Creek gas plant
- Tied in West Dunvegan wells which resulted in 4.5 Mmcfd net sales
- Recommissioned amine unit at Tangent gas plant to bring shut in sour gas on stream

2001 Planned Activity

- Drill 69 gross (56 net) exploration wells and 60 gross (43 net) development wells
- Construct a sour gas plant at Rycroft
- Start up West Culp sour gas plant in November 2000
- Tie in new sour gas discovery at Mirage
- Implement various waterfloods in the southwest Peace River Arch
- Install booster compressor at George
- New exploration drilling in Knopcik to target deeper Triassic and Devonian prospects, some on lands acquired as part of the Ulster acquisition



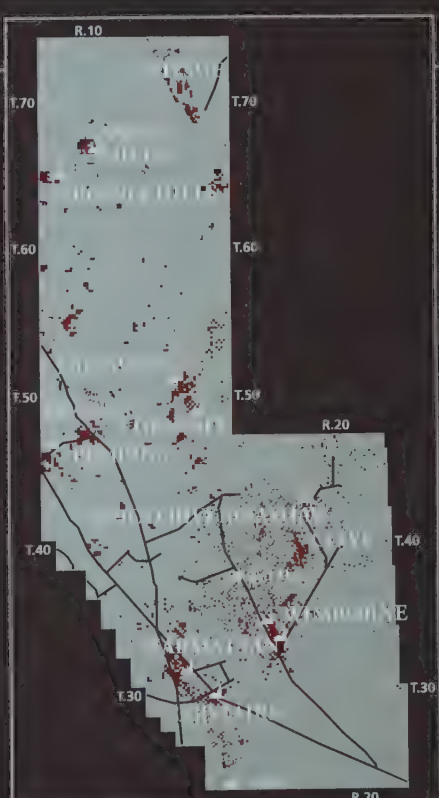
NORTHERN PLAINS

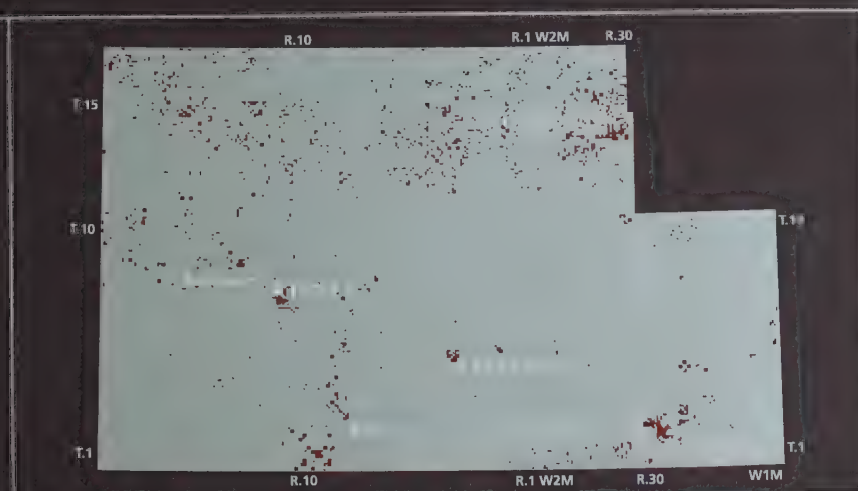
2000 Activity and Results

- Sales – 170 Mmcfd and 7,139 Bpd
- Acquired 83,800 net acres of Crown land and Ulster acquisition added 3,800 net acres
- Hold 894,400 net undeveloped acres in region
- Drilled 350 gross (290 net) wells, resulting in 107 gas wells, 193 oil wells and 50 dry holes
- Successful gas drilling programs and increased compression in northeast Alberta added 45 Mmcfd of new production capability
- Heavy oil production increased to an exit rate of 7,200 Bpd from 3,000 Bpd

2001 Planned Activity

- Drill 126 gross (120 net) exploration wells and 202 gross (172 net) development wells
- Equip and tie in 80 gas wells and construct 110 miles of flow lines, install 6 compressors
- Acquire 250 miles of seismic data
- Continue heavy oil exploration and development drilling





CENTRAL AND SOUTHERN PLAINS

2000 Activity and Results

- Sales – 56 Mmcfd and 15,483 Bpd
- Acquired 18,100 net acres of Crown land and Ulster acquisition added 130,500 net acres
- Hold 721,000 net undeveloped acres in region
- Drilled 62 gross (41 net) wells, resulting in 22 gas wells, 28 oil wells and 12 dry holes
- Added significant oil and gas assets in the Clive and Wimborne areas as a result of the Ulster acquisition
- Significant expansions of existing infrastructure in the Innes and Steelman areas

2001 Planned Activity

- Drill 50 gross (46 net) exploration wells and 107 gross (36 net) development wells
- New exploration drilling to target deeper Devonian prospects in the Pembina/Brazeau areas
- Development drilling to exploit Mississippian oil at Steelman and Innes and Devonian oil at Wimborne

Capital expenditures in 2000 increased by 136 percent to $669 million, representing 84 percent of cash flow. Of these, plant construction and expansion and pipeline installation expenditures increased by 92 percent to $144 million. At West Culp in the Peace River Arch, a new 20 million cubic feet per day gas plant with acid gas reinjection was constructed, with operations commencing in November 2000.

LAND Anderson Exploration's undeveloped land inventory in the western provinces increased 25 percent over 1999 to 3.8 million net acres as a result of the Ulster acquisition and aggressive participation in the Crown land sales. This undeveloped land base is located 66 percent in Alberta, 21 percent in British Columbia, 12 percent in Saskatchewan and one percent in Manitoba. The average working interest in this land base is 75 percent. In addition, Anderson Exploration was very active in acquiring exploration acreage in the Mackenzie Delta and shallow water Beaufort Sea and the Central Mackenzie Valley areas of the Northwest Territories. As well, the Company acquired two Exploration Permits in the Eagle Plain area on the Dempster Highway in the Yukon. As a result of the fiscal 2000 activity North of 60°, Anderson Exploration is now the largest holder of Exploration Licence and Concession acreage in the Mackenzie Delta and shallow water Beaufort Sea area with a working interest in 48 percent of the total acreage made available to the industry and a 33 percent ownership on a net basis.

SUMMARY OF UNDEVELOPED LAND HOLDINGS At September 30

(working interest lands, thousands of acres)	**2000**		1999	
	Gross	**Net**	Gross	Net
Western provinces	**5,151**	**3,849**	3,968	3,081
North of 60° and other frontier	**4,303**	**2,012**	1,671	353
Total	**9,454**	**5,861**	5,639	3,434

WESTERN CANADA CROWN SALE LAND ACQUISITIONS Years ended September 30

	2000	1999
Expenditures (thousands of dollars)	**$ 81,189**	$ 31,749
Net acres acquired	**495,337**	248,065
Price per acre	**$ 164**	$ 128

Industry activity at Crown land sales increased in 2000 when compared to 1999 as a result of strong commodity prices. In the four western provinces for the year ending September 30, 2000, $1.2 billion was spent by industry in total bonus payments to acquire 11.3 million acres of petroleum and natural gas rights, excluding oilsands rights, compared to $622 million for 10 million acres in the previous year. This represents a 93 percent increase in total Crown land sale expenditures, a 13 percent increase in total acreage sold and a 71 percent increase in the price per acre paid by industry over 1999. The Company's total expenditures and price paid per acre increased 156 percent and 28 percent over 1999, respectively, in support of its aggressive exploration program.

NORTH OF 60° AND OTHER FRONTIER ACREAGE At September 30

(thousands of acres)	2000		1999	
	Gross	**Net**	Gross	Net
Exploration Licences, Permits and Concessions				
Mackenzie Delta, N.W.T.	**1,021**	**437**	365	146
Shallow Water Beaufort Sea, N.W.T.	**836**	**836**	–	–
	1,857	**1,273**	365	146
Central Mackenzie Valley, N.W.T.	**318**	**318**	–	–
Eagle Plain, Yukon	**198**	**198**	–	–
	2,373	**1,789**	365	146
Other North of 60° and East Coast Offshore	**1,930**	**223**	1,306	207
Total	**4,303**	**2,012**	1,671	353

In fiscal 2000, the Company acquired interests in seven Federal Exploration Licences, two Yukon Permits and two Inuvialuit Concession Agreements North of 60° by entering into work proposals estimated to cost $335 million. The interests comprise 2.0 million gross acres or 1.6 million net acres and bring Anderson Exploration's total work proposals on all North of 60° acreage to $377 million. The Federal Licences and Yukon Permits require 25 percent work deposits that are recoverable as eligible expenditures are made. The Company has letters of credit in place to cover these deposits. Expenditures under the work proposals will be made over a five year period with the requirement to drill at least one well on each block. If completed, this activity will extend the terms of the agreements for another four years. Under the Inuvialuit Concession Agreements, there is a competitive bid scenario similar to the Crown land sales in the western provinces and bonus payments of $16 million were made in addition to the work component. In this case, the cost to conduct the activities that have been proposed under the Concession Agreements has been estimated and this estimate is subject to change. The Inuvialuit also retain certain back in rights on the declaration of a discovery.

Anderson Exploration is the operator of nine of the 13 blocks acquired in 1999 and 2000. Petro-Canada is the operator of four of the blocks in the Mackenzie Delta.

DRILLING Anderson Exploration participated in drilling 630 wells for oil and gas in fiscal 2000. This 131 percent increase in activity over 1999 was largely due to improved commodity prices. The average working interest in wells drilled was 74 percent in 2000 compared to 65 percent in 1999. Expenditures for the drilling, completion and recompletion of wells were $349 million versus $121 million in 1999. Of these expenditures, 59 percent were in the traditionally active areas of the northern Plains, northeast British Columbia and the Peace River Arch. Forty-one percent of the expenditures were in the recently established areas of Foothills, Deep Basin and central and southern Plains. No Frontier drilling or completion expenditures were incurred in 2000.

The Company participated in 402 development wells. The heavy oil drilling program accounted for approximately 40 percent of the development wells. The Company participated in 228 exploration wells. Seventy-six percent of the successful exploration wells were gas.

In fiscal 2001, the Company plans to participate in over 800 gross wells, representing the busiest drilling year ever for Anderson Exploration. Drilling rigs have been contracted for the busy winter season to accomplish this goal. The trend towards deeper drilling continues as approximately one quarter of the 2001 exploratory drilling budget is directed to wells deeper than 2,800 metres.

SUMMARY OF WELLS DRILLED Years ended September 30

(number of wells)	2000		1999	
	Gross	**Net**	Gross	Net
Gas wells	**277**	**185**	179	103
Oil wells	**234**	**184**	46	35
Dry holes	**119**	**100**	48	41
	630	**469**	273	179
Service wells	**6**	**2**	3	1
Total	**636**	**471**	276	180

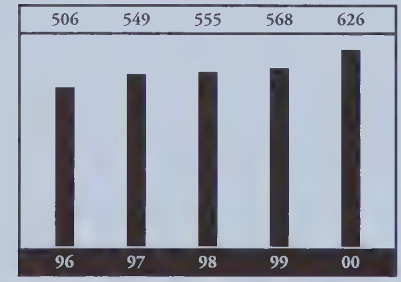
CONSTRUCTION In fiscal 2000, Anderson Exploration spent $144 million on new plant construction, expansions and the installation of approximately 260 miles of pipeline, a 92 percent increase in expenditures over the previous year. The following are some of the major projects completed. At Swan Hills, miscible flood facilities were expanded and a new 41,000 barrel per day water injection facility was installed. Construction of a new 30 million cubic feet per day gathering system to accommodate new wells at Narraway was started but was delayed due to an extremely wet summer in the Foothills. The Narraway pipeline should commence operation in January 2001. In February 2000, compression was added to the Kotaneelee plant in the Yukon to maintain deliverability from the two producing wells by offsetting the expected impact of increased line pressure from upstream Fort Liard production. In northeast British Columbia, 15 wells were tied in and approximately 29 million cubic feet per day of compression capacity was added in the Martin Creek, Wargen and Nig Creek areas. In the Tooga area, seven wells were tied in to existing infrastructure increasing production capability from 15 to 23 million cubic feet per day. In the northeast

Alberta shallow gas area, approximately 13.5 million cubic feet per day of booster compression was added and 31 wells were tied in, and at Marten Hills the combined capacity of the two area plants was increased from 33 to 55 million cubic feet per day. After a successful public consultation program, construction was started on a new 20 million cubic feet per day gas plant with acid gas reinjection at West Culp. This plant commenced operations in November 2000. Construction activity increased throughout fiscal 2000 and is expected to continue in 2001 as the Company intensifies property development. As well, work is underway on a number of facility and pipeline projects on properties that were acquired from Ulster.

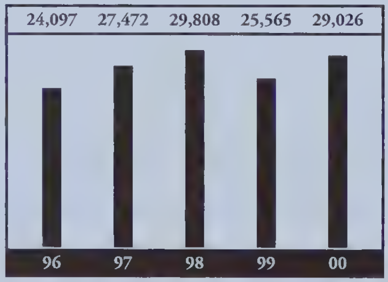
PRODUCTION/SALES Natural gas sales increased 10 percent to 626 million cubic feet per day in fiscal 2000 from 568 million cubic feet per day in 1999. Sales from Ulster were included after May 17 and were a significant component of the increase. The biggest contribution from Ulster was at Wapiti, where Anderson Exploration activity also contributed to the increase. Increases also came from further development in Tooga in northeast British Columbia and at Woodenhouse and Marten Hills in northeast Alberta. Nineteen million cubic feet per day of annualized gas sales additions came from new producing areas in the Deep Basin and Foothills. More of the Company's gas production additions will come from these deeper areas in the future. These increases were offset to some extent by natural declines in a number of other fields. At Kotaneelee in the Yukon, a payout calculation resulted in reductions to working interest sales.

Crude oil sales averaged 29,026 barrels per day in 2000, a 14 percent increase over the prior year. Major additions were at Wimborne, an Ulster property in central Alberta, and at Innes and Steelman in southeast Saskatchewan. Oil price increases during the year stimulated exploration and development in the Lloydminster area where heavy oil sales increased 96 percent to 5,354 barrels per day in 2000. Exit production of heavy oil exceeded 7,200 barrels per day. This trend of active heavy oil development will continue into 2001. NGL sales increased 42 percent to average 11,379 barrels per day in fiscal 2000 versus 8,020 barrels per day in 1999. The gas production acquired through Ulster is liquids rich with most of the NGL produced at the Wapiti deep cut facility. NGL sales increases were also a result of the diversion of part of the raw gas in Belloy to the Dunvegan plant in the Peace River Arch.

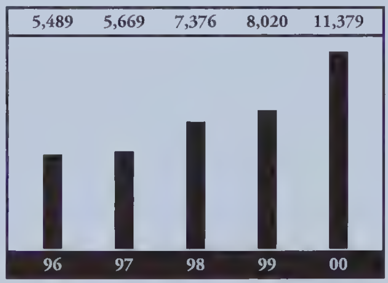
DAILY NATURAL GAS SALES
(Mmcfd)



DAILY CRUDE OIL SALES
(Bpd)



DAILY NGL SALES
(Bpd)



DAILY NATURAL GAS SALES

Years ended September 30

(Mmcfd)	2000	1999
Leismer/Kirby	**53.8**	56.9
Dunvegan	**53.8**	54.4
Bilbo/Karr/Wapiti	**42.3**	10.8
Birley/Wargen	**35.4**	36.1
Woodenhouse	**25.2**	21.7
Belloy	**21.9**	19.5
Peggo/Pesh/Tooga	**20.5**	13.5
Cecil Royce	**17.1**	18.7
Ring Border	**16.6**	17.0
Marten Hills	**15.7**	10.4
Eaglesham/Culp	**14.7**	16.4
Hines Creek	**14.6**	14.7
Blackstone	**14.6**	19.8
Mistahae	**14.1**	11.5
Harmattan	**13.3**	11.9
Eagle	**11.7**	10.4
Kotaneelee	**10.4**	15.8
Normandville	**9.9**	10.8
Puskwaskau	**9.6**	10.8
Findley	**8.4**	4.4
Other and Royalty	**202.8**	182.2
Total	**626.4**	567.7

DAILY CRUDE OIL AND NGL SALES

Years ended September 30

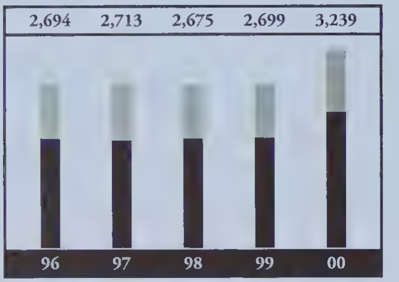
(Bpd)	2000	1999
Crude Oil		
Lloydminster	**5,468**	2,725
Swan Hills	**4,743**	5,394
Eagle	**3,276**	2,999
Hayter	**1,363**	1,549
Valhalla	**1,331**	1,684
Innes	**965**	771
Stoddart	**889**	974
Wimborne	**882**	–
Mitsue	**850**	1,095
Virginia Hills	**843**	889
Pierson	**752**	745
Steelman	**690**	132
Pembina/Brazeau	**541**	540
Progress	**516**	499
Gainsborough	**483**	668
Other and Royalty	**5,434**	4,901
	29,026	25,565
NGL		
Dunvegan	**2,599**	1,764
Bilbo/Wapiti/Karr	**1,987**	598
Birley/Wargen	**1,060**	1,016
Harmattan	**637**	332
Belloy	**516**	247
Other and Royalty	**4,580**	4,063
	11,379	8,020
Total	**40,405**	33,585

2000 QUARTERLY SALES

	Q1	Q2	Q3	Q4	Year
Natural gas (Mmcfd)	572	562	668	703	**626**
Light/medium crude oil (Bpd)	21,813	22,333	23,803	26,723	**23,672**
Heavy crude oil (Bpd)	4,010	5,379	5,806	6,228	**5,354**
Total crude oil (Bpd)	25,823	27,712	29,609	32,951	**29,026**
NGL (Bpd)	9,514	9,740	12,571	13,684	**11,379**
Total liquids (Bpd)	35,337	37,452	42,180	46,635	**40,405**

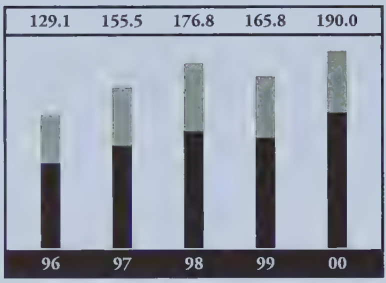
RESERVES In fiscal 2000, the Company replaced 283 percent of its natural gas production, 325 percent of its crude oil production and 602 percent of its NGL production with proven reserve additions after all revisions. Before revisions, the Company added 722 billion cubic feet of proven natural gas reserves, 39.4 million barrels of proven crude oil reserves and 24.4 million barrels of proven NGL reserves through drilling and net property acquisitions. Of these additions, the Ulster acquisition accounted for 435 billion cubic feet of gas, 27.7 million barrels of oil and 20.0 million barrels of NGL reserves. Revisions reduced proven gas reserves by 74 billion cubic feet and oil reserves by 4.9 million barrels. NGL proven reserves had a 0.6 million barrel positive revision. Total proven natural gas reserves at September 30, 2000 increased 23 percent over last year. Total proven crude oil reserves were up 22 percent and total proven NGL reserves were up 53 percent. On a barrel equivalent basis, the Company replaced 316 percent of its production with proven reserves.

NATURAL GAS RESERVES
(Bcf)
Proven Probable



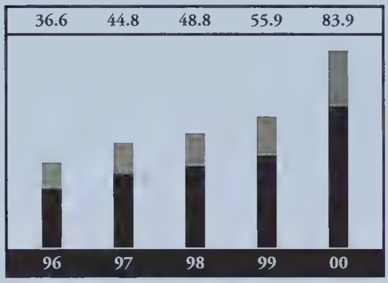
	96	97	98	99	00
Probable	896	945	917	887	1,008
Proven	1,798	1,768	1,758	1,812	2,231

CRUDE OIL RESERVES
(Mmbbls)
Proven Probable



	96	97	98	99	00
Probable	46.8	56.3	63.8	59.0	59.3
Proven	82.3	99.2	113.0	106.8	130.7

NGL RESERVES
(Mmbbls)
Proven Probable



	96	97	98	99	00
Probable	11.2	13.1	13.8	16.6	23.7
Proven	25.4	31.7	35.0	39.3	60.2

The Company's acquisition of Ulster Petroleums Ltd. in May 2000 was the single major reserve addition during the year. The purchase price of Ulster, including assumed debt, was $1.0 billion. On a total proven reserve basis, the cost of the acquisition was $8.33 per barrel of oil equivalent. The addition of Ulster resulted in the establishment of two new core operating areas, the Deep Basin and central Alberta. The majority of Ulster gas and NGL reserves are concentrated in the Deep Basin which includes Wapiti, Elmworth and Karr. Ulster crude oil reserves are largely contained in the Wimborne and Clive fields in central Alberta.

Significant proven gas additions, resulting in 54 percent of total drilling additions, were realized at Bighorn, Marten Hills, Narraway, Pinto, Tooga and Wapiti/Karr. Two thirds of the oil drilling additions were heavy oil in the Lloydminster area. The Company also conducted significant heavy oil drilling which did not add reserves, but converted proven undeveloped reserves to proven developed producing reserves. The Innes and Steelman oil pools of southeastern Saskatchewan accounted for 13 percent of the oil drilling additions.

In anticipation of more stringent generally accepted reserves definitions, the Company has adopted higher proven and probable reserve confidence levels. As a result, a number of small negative reserve revisions occurred at the individual property level. Negative gas revisions were recorded for Corn Lake and Hospital Creek in northeast Alberta, Puskwaskau in the Peace River Arch and the Findley Mississippian in the Foothills due to performance related issues. These properties collectively accounted for negative revisions of 42 billion cubic feet of proven and 100 billion cubic feet of proven plus probable reserves. The majority of the negative oil revisions were in the Edam and East Eagle fields.

The Company's oil and gas related expenditures in fiscal 2000 were $1.7 billion, including the Ulster acquisition. Overall finding and development costs, after revisions, were $9.84 per barrel of oil equivalent for proven reserves. Finding and development costs substantially increased over the fiscal 1999 value of $5.31 due to lower than anticipated gas drilling additions, increased pre-investment costs for land and seismic and higher costs of goods and services due to increased industry activity. Although the cost pressures will continue, reduced land acquisitions in 2001 and increased activity in the traditionally low finding and development cost areas of greater Wapiti and Lloydminster should more than offset this.

The Company's proven reserve life indices are 9.7 years for gas, 12.3 years for oil and 14.5 years for NGL. In 2001, a full year of production from the Ulster lands will put downward pressure on these indices.

In fiscal 2000, the Company's engineering personnel evaluated 70 percent of the proven reserves with the balance evaluated by independent engineering consultants. The Company will continue to use independent engineering consultants to evaluate a portion of its properties in fiscal 2001. In November 1999, the Board of Directors of the Company established a Reserves Committee made up of three independent directors. This Committee's mandate is to review the Company's reserve determination practices and to advise the Board in respect of both internal and independent evaluations of the Company's petroleum and natural gas reserves.

NATURAL GAS RESERVES

(Company interest, Bcf)	Proven	Probable	Total
As at September 30, 1999	1,812	887	2,699
Drilling	284	173	457
Property acquisitions	438	130	568
Property dispositions	–	–	–
Total additions	722	303	1,025
Revisions	(74)	(182)	(256)
Sales	(229)	–	(229)
Net gain	419	121	540
As at September 30, 2000	**2,231**	**1,008**	**3,239**

CRUDE OIL RESERVES

(Company interest, Mbbls)	Proven	Probable	Total
As at September 30, 1999	106,755	59,016	165,771
Drilling	11,502	3,976	15,478
Property acquisitions	28,348	4,363	32,711
Property dispositions	(430)	(85)	(515)
Total additions	39,420	8,254	47,674
Revisions	(4,887)	(7,990)	(12,877)
Sales	(10,623)	–	(10,623)
Net gain	23,910	264	24,174
As at September 30, 2000	**130,665**	**59,280**	**189,945**

NGL RESERVES

(Company interest, Mbbls)	Proven	Probable	Total
As at September 30, 1999	39,287	16,614	55,901
Drilling	4,358	3,957	8,315
Property acquisitions	20,086	4,445	24,531
Property dispositions	–	–	–
Total additions	24,444	8,402	32,846
Revisions	646	(1,270)	(624)
Sales	(4,165)	–	(4,165)
Net gain	20,925	7,132	28,057
As at September 30, 2000	**60,212**	**23,746**	**83,958**

MARKETING AND PRODUCT PRICES In fiscal 2000, the industry enjoyed the highest natural gas prices since the start of deregulation 15 years ago. With increased gas pipeline export capacity from western Canada, Canadian gas prices rose along with U.S. prices resulting in the highest annual average gas price in Anderson Exploration's history. With additional gas export capacity due to come on stream in the form of the Alliance pipeline and declining industry deliverability in western Canada, Canadian prices should remain strong for the foreseeable future. Most certainly, the average natural gas price for fiscal 2001 will exceed that of fiscal 2000.

Crude oil prices increased steadily throughout the year. The effect of production cuts by some of the world's major producing countries in 1999 carried over into the current year. Production increases by these same countries in 2000 did not have the anticipated dampening effect on prices as world oil demand stayed strong throughout the year and inventories remained at the lowest level in over 20 years.

HISTORICAL ANNUAL AVERAGE COMPANY PRICES

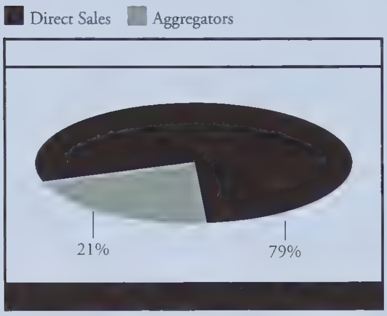
Fiscal Year	Natural Gas ($/Mcf)	Crude Oil ($/Bbl)
1985	2.82	33.76
1986	2.46	23.49
1987	1.87	21.65
1988	1.68	18.75
1989	1.65	18.49
1990	1.70	22.16
1991	1.52	24.19
1992	1.33	20.29
1993	1.67	20.66
1994	1.98	19.52
1995	1.43	22.05
1996	1.59	25.22
1997	1.91	25.37
1998	1.94	18.53
1999	2.48	21.17
2000	**3.83**	**37.55**

NATURAL GAS In fiscal 2000, Anderson Exploration's natural gas price averaged $3.83 per thousand cubic feet at the plant gate, an improvement of 54 percent over 1999 at $2.48. Alberta spot and NYMEX (New York Mercantile Exchange) prices rose by 49 percent and 48 percent, respectively, over the same time frame. The Company's price in September, the last month of the fiscal year, was $5.38 per thousand cubic feet as compared to $2.87 a year earlier.

The Ulster acquisition did not materially change the Company's marketing portfolio. In fiscal 2000, 79 percent of the Company's natural gas was sold directly. Virtually all of these sales occurred under short term arrangements, primarily to marketing intermediaries at prices set in western Canada. The balance of the Company's sales were to aggregators such as ProGas, TransCanada, CanWest and Pan-Alberta. The proportion of sales to aggregators is expected to decline further over time.

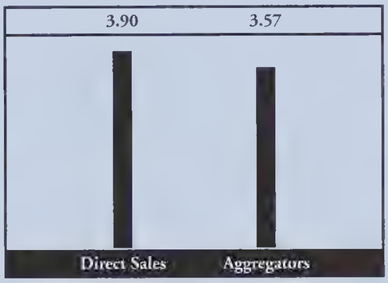
The tight supply and demand fundamentals will continue to support strong natural gas prices both in the U.S. and Canada. Anderson Exploration is well positioned to take advantage of these high prices as we have not hedged prices on any of our production. About 84 percent of Company sales in fiscal 2001 will be directly linked to premium priced western Canadian indices.

2000 NATURAL GAS SALES DISTRIBUTION



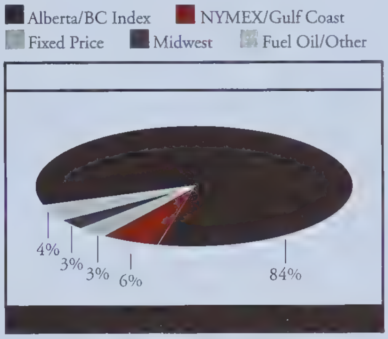
Gas Sales: 626 Mmcfd

2000 NATURAL GAS PRICE ($ per Mcf)



Weighted Average Price: $3.83

2000/01 NATURAL GAS SALES PORTFOLIO (Nov. 2000 to Oct. 2001)

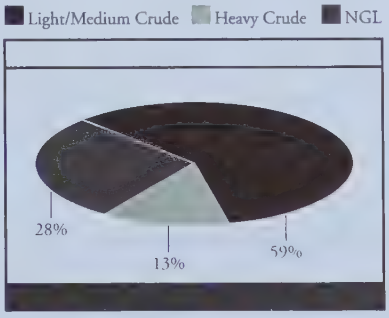


Estimated Gas Sales: 750 Mmcfd

CRUDE OIL AND NGL The price of West Texas Intermediate (WTI), as traded on the NYMEX, is the initial pricing point for virtually all of the Company's crude oil sales. WTI prices rose steadily throughout the year peaking at U.S.$33.87 per barrel in September 2000. For the 2000 fiscal year, WTI averaged U.S.$28.36 per barrel, a 74 percent increase over the U.S.$16.34 per barrel recorded last year. Very strong WTI prices, combined with a weak Canadian dollar and narrower differentials for light sweet crude oil at Edmonton, resulted in Anderson Exploration's highest crude oil price since 1985. The Company's realized price for crude oil in fiscal 2000 was $37.55 per barrel, up 77 percent from last year. Strong ongoing supply and demand fundamentals, including low inventories, solid world demand associated with strong economies and limited OPEC excess productive capacity, should support world oil prices in the near term.

Natural gas liquids increased from 24 to 28 percent of Anderson Exploration's total liquids sales in fiscal 2000 primarily due to the Ulster acquisition. The Company realized a weighted average price for its NGL of $29.06 per barrel, an increase of 84 percent compared to 1999. NGL are sold as a mix or as individual components of ethane, propane, butane and condensate. Ethane prices are directly correlated to natural gas prices, as ethane typically sells on a gas basis plus a premium. Therefore, ethane prices tracked upward with higher natural gas prices. Propane and butane have their own supply/demand drivers but prices generally trend with crude oil and consequently prices increased substantially in the current year. Condensate generally trades at a slight discount to light sweet crude at Edmonton but can trade at a premium if it is in strong demand as a diluent to transport heavy crude. This year condensate traded at a premium to crude oil reflecting increased heavy oil production in western Canada. Continued strength in the total energy price structure is expected to support strong NGL prices in fiscal 2001.

2000 CRUDE OIL AND NGL SALES MIX



Liquids Sales: 40,405 Bpd

2000 NGL STREAM

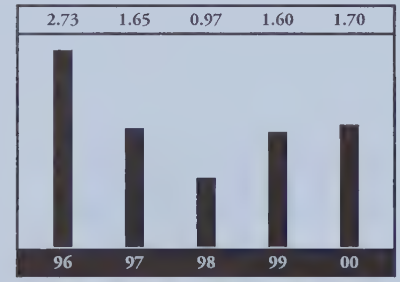
	Sales Volumes (Bpd)	% of Stream	Price per Bbl
Ethane	2,399	21%	$12.43
Propane	2,898	25%	$26.76
Butane	2,028	18%	$30.68
Condensate	4,054	36%	$39.74
Total	11,379	100%	$29.06

STRADDLE PLANTS Anderson Exploration owns an average 10.4 percent interest in two straddle plants located at Empress, Alberta. The plants are located on main gas export transmission lines at the Alberta border and extract NGL, primarily ethane, propane and butane. The Company processes its own gas and a small amount of third party gas at these facilities. Anderson Exploration's share of the NGL from this facility was 3,330 barrels per day in 2000 compared to 2,133 barrels per day last year. These volumes are not included in the Company's NGL sales figures. Volumes increased year over year reflecting a full year of the benefit of plant modifications made last year. Anderson Exploration profits from the difference between the energy value of NGL sold as liquid and the value of maintaining the energy content in gaseous form and selling it as natural gas. High NGL prices resulted in a profit of $5.1 million on these assets in fiscal 2000.

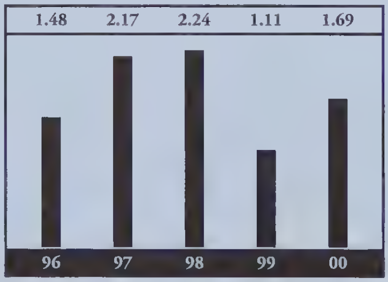
HEALTH, SAFETY AND ENVIRONMENT Anderson Exploration is committed to protecting the health and safety of our employees and the public, as well as to preserving the quality of the environment.

WORKPLACE HEALTH AND SAFETY An ongoing priority for Anderson Exploration is to provide a safe workplace for both employees and contractors. While the Company continues to be one of the most active exploration companies in western Canada, Anderson Exploration's injury and motor vehicle accident rates remained at or below the average rates for our industry.

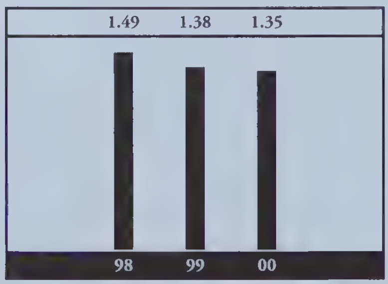
EMPLOYEE REPORTABLE INJURIES
(medical aid and lost time injuries per 200,000 manhours)



EMPLOYEE REPORTABLE MOTOR VEHICLE ACCIDENTS
(motor vehicle accidents per 1,000,000 kilometres)



CONTRACTOR LOST TIME INJURIES
(lost time injuries per 200,000 manhours)



ENVIRONMENTAL PROTECTION Anderson Exploration's goal is to continue to reduce the environmental impact of our operations. The Company continued to develop and implement equipment integrity plans and mitigation programs for its pipelines, pressure vessels, storage tanks and electrical systems. These programs form an integral

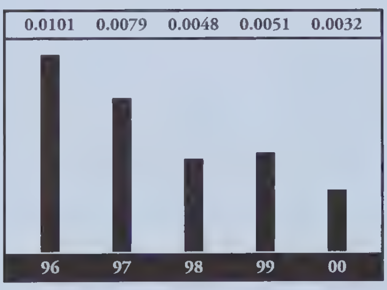
component of the Company's effort to protect the public and the environment by ensuring the safe operation of our facilities and pipelines. As a direct result of the pipeline programs, a 37 percent reduction in the Company's spill rate was realized during the past year.

The Company continues to increase its focus on identifying opportunities to conserve energy and reduce emissions from its facilities. These efforts resulted in a decrease in estimated gas emissions by over 125,000 tonnes of CO_2 equivalent, a 258 percent improvement compared to the previous year.

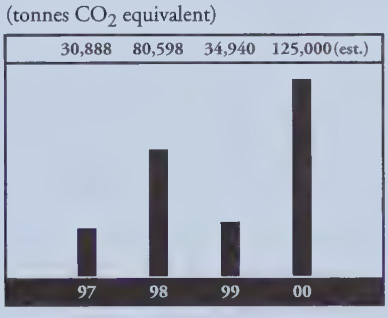
In support of the Company's aggressive exploration plans North of 60°, environmental assessments are required prior to the submission of applications for regulatory approvals to proceed with exploration activities. As an example, the Company completed a fish habitat assessment at a cost of $500,000 as part of its application to conduct geophysical work in the Tuktoyaktuk region. In addition, a significant level of community consultation is being carried out as part of the approval process.

During 2000, Anderson Exploration increased its spending on well abandonment and site restoration activities by 60 percent to $10 million. In total, 112 wells were abandoned and reclamation certificates were received for 101 sites, increases of 93 and 226 percent, respectively. The most active remediation programs were in the Turner Valley, Swan Hills, Wimborne and Fairview areas.

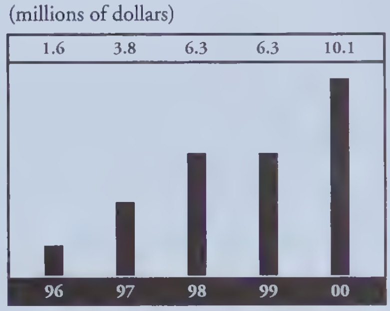
SPILL RATE
(percentage of total fluid produced)



EMISSION REDUCTION SUCCESS STORIES
(tonnes CO_2 equivalent)



WELL ABANDONMENT AND SITE RESTORATION EXPENDITURES
(millions of dollars)



REGULATORY AND COMMUNITY RELATIONS Improved management of the Company's compliance and community relations continues to be high priority. As part of the Company's strategy for improving landowner communications, a number of open houses were held throughout the year. The response from residents to these efforts was positive, particularly in the Culp and Wimborne areas where major development activities are proceeding with public support.

In an effort to ensure all the Company's operations remain in compliance with regulatory requirements, a cycle of detailed safety, environmental and equipment integrity audits of its operating facilities is completed every five years. The internal audits completed in fiscal 2000 confirm that there is continued improvement in the implementation of health, safety and environmental management practices.

On May 17, 2000, Anderson Exploration acquired Ulster Petroleums Ltd. which was a strategic and synergistic fit for the Company. For example, the combination of the assets of the two companies in the Wapiti area created Anderson Exploration's largest gas property. The combined land holdings, gas plants, pipeline interests and seismic data sets have provided exploration and operating advantages and opportunities.

The following discussion and analysis of financial results should be read in conjunction with the consolidated financial statements for the year ended September 30, 2000 and is based on information available at November 15, 2000. Supplementary operating and financial statistics can be found on pages 66 and 67 of this annual report. Information provided herein for fiscal 2001 is based on assumptions regarding future events and is subject to risks and uncertainties that may cause actual results to vary materially from these estimates. Where amounts are expressed on a barrel of oil equivalent basis, gas volumes have been converted to barrels of oil at six thousand cubic feet per barrel. This conversion ratio approximates the relative energy content between gas and oil.

RESULTS OF OPERATIONS

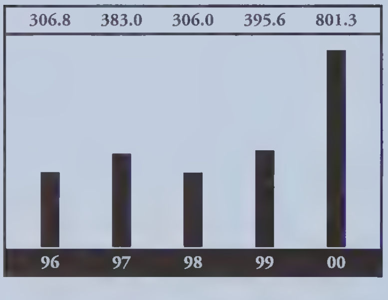
OVERVIEW Fiscal 2000 was characterized by product price increases to levels significantly higher than those experienced in recent years. Prices and sales volumes on a barrel of oil equivalent basis increased 63 percent and 13 percent, respectively, over fiscal 1999. Record setting results were achieved throughout the year. Cash flow from operations increased 103 percent over last year and total earnings increased 345 percent. Total earnings include an after tax gain of $63.5 million recorded in the third quarter on the sale of the Company's 50 percent interest in Federated Pipe Lines Ltd. Federated results are shown as discontinued operations in the consolidated financial statements and in this discussion and analysis. Earnings from continuing oil and gas operations increased 274 percent from last year.

On May 17, 2000, the Company completed the acquisition of Ulster Petroleums Ltd. The purchase price was $645.7 million before transaction costs and the assumption of Ulster's existing debt. Production from the Ulster properties is included in the Company's results from the date of acquisition, or for approximately one third of the fiscal year. With the acquisition of Ulster, the sale of Federated and the acquisition of significant frontier acreage during fiscal 2000, the Company has strengthened and streamlined its position as a senior Canadian oil and gas explorer and producer heavily leveraged to natural gas.

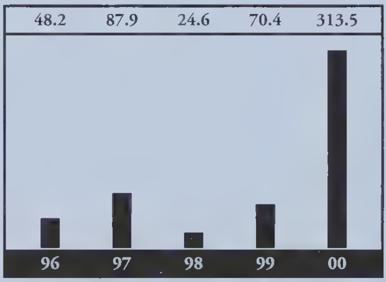
CASH FLOW FROM OPERATIONS AND EARNINGS Years ended September 30

(millions of dollars, except per share amounts)	2000	1999	% Change
Cash flow from operations			
Continuing operations (oil and gas)	**$ 796.9**	$ 387.6	106
Discontinued operations (pipeline)	**4.4**	8.0	(45)
Cash flow from operations	**$ 801.3**	$ 395.6	103
Cash flow from operations per share (basic)	**$ 6.29**	$ 3.19	97
Earnings			
Continuing operations (oil and gas)	**$ 248.2**	$ 66.4	274
Discontinued operations (pipeline)	**65.3**	4.0	1,533
Earnings	**$ 313.5**	$ 70.4	345
Earnings per share (basic)	**$ 2.46**	$ 0.57	332

CASH FLOW FROM OPERATIONS
(millions of dollars)



EARNINGS
(millions of dollars)



OIL AND GAS REVENUES Oil and gas revenues in fiscal 2000 exceeded $1 billion for the first time in the Company's history. On a barrel of oil equivalent basis, prices increased 63 percent over fiscal 1999 and sales volumes increased 13 percent. The following table shows the components of revenue last year and this year, as well as the effect of changes in prices and volumes on revenue. In fiscal 2000, natural gas sales made up 72 percent of total sales volume compared to 74 percent last year.

OIL AND GAS REVENUES

(millions of dollars)	Gas	Oil	NGL	Other*	Total
Fiscal 1999 revenue	$ 513.5	$ 197.5	$ 46.3	$ 13.6	$ 770.9
Effect of increase in product price	280.8	152.9	38.7	–	472.4
Effect of increase in sales volumes	84.5	48.5	36.0	–	169.0
Other	–	–	–	4.8	4.8
Fiscal 2000 revenue	**$ 878.8**	**$ 398.9**	**$ 121.0**	**$ 18.4**	**$ 1,417.1**
Percentage of total revenue – 1999	67%	26%	6%	1%	100%
Percentage of total revenue – 2000	**62%**	**28%**	**9%**	**1%**	**100%**
Percentage of total sales volumes – 1999	74%	20%	6%		100%
Percentage of total sales volumes – 2000	**72%**	**20%**	**8%**		**100%**
Fiscal 1999 average price	$ 2.48/Mcf	$ 21.17/Bbl	$ 15.82/Bbl		$ 16.47/Boe
Fiscal 2000 average price	**$ 3.83/Mcf**	**$37.55/Bbl**	**$29.06/Bbl**		**$26.74/Boe**

* Consists of amortization of natural gas contract settlement payments, net straddle plant revenues, gains on brokered gas sales and other gains/losses.

Natural gas sales volumes averaged 626 million cubic feet per day, an increase of 10 percent over last year, primarily due to the inclusion of sales from Ulster properties from May 17 to September 30. The Ulster acquisition contributed 42 million cubic feet per day to the average daily sales volumes for fiscal 2000. Sales volumes also increased in northeast British Columbia and northeast Alberta as a result of new well tie ins from the winter drilling program and workover activity completed in the year. These increases were partially offset by declines in other mature properties. Sales volumes were slightly below expectations as a result of drilling delays caused by wet weather and the internal integration of Ulster operations in the last half of the year. The integration of Ulster is now complete. Natural gas sales are expected to increase to 750 million cubic feet per day in fiscal 2001 as a result of an aggressive drilling program focused on natural gas plays and the inclusion of the Ulster properties for a full year.

Natural gas prices increased 54 percent over last year, despite warmer than normal winter temperatures, to average $3.83 per thousand cubic feet. Demand from the United States continues to increase, and working gas volumes in storage in the United States and Canada during the summer fill season remained substantially lower than last year and the trailing five year average. As a significant portion of the Company's gas sales portfolio is linked to premium Alberta and British Columbia indices, the Company was able to achieve a high corporate average gas price as western Canadian gas prices strengthened. In fiscal 2000, the Company sold approximately 79 percent of its natural gas primarily to marketing intermediaries, but also to end users and local distribution companies, under contracts of varying terms. The remaining 21 percent was sold to supply aggregators, who in turn sold the gas to purchasers along gas pipelines, generally at market sensitive prices. In fiscal 2001, it is anticipated that 84 percent of our natural gas sales portfolio will be priced in western Canada.

NGL volumes increased 42 percent to 11,379 barrels per day in the 2000 fiscal year. The inclusion of sales volumes from Ulster properties and increased ethane production at Dunvegan were the major contributors to the increase. NGL prices made a significant recovery in the fiscal year, increasing 84 percent from last year. The Company sells its NGL both as NGL mix and as individual components of condensate, propane, butane and ethane, primarily in Alberta. Sales prices are indexed to major NGL market centres, such as Edmonton, Alberta. NGL sales volumes are expected to increase to 14,000 barrels per day in fiscal 2001.

NATURAL GAS AND NGL NETBACKS Years ended September 30

(per Mcf*)	**2000**	1999	% Change
Sales revenue	**$ 3.93**	$ 2.49	58
Royalties	**(0.84)**	(0.43)	95
Operating costs	**(0.50)**	(0.43)	16
Netback	**$ 2.59**	$ 1.63	59
Royalty percentage	**21%**	17%	24
Daily sales volumes – natural gas (Mmcfd)	**626**	568	10
Daily sales volumes – NGL (Bpd)	**11,379**	8,020	42

* NGL converted to natural gas at 1 Bbl = 6 Mcf

Light and medium oil sales volumes increased four percent from last year to 23,672 barrels per day and heavy oil volumes increased 96 percent to 5,354 barrels per day. New light and medium oil production from the Ulster properties contributed to the increase in these volumes, as did development drilling in the Williston Basin area of southeast Saskatchewan, primarily at Innes and Steelman. In the Lloydminster heavy oil area, additional development drilling resulted in nearly doubled sales volumes over last year. Total oil sales are expected to increase about 24 percent to 36,000 barrels per day in fiscal 2001, of which approximately 75 percent will be light and medium oil.

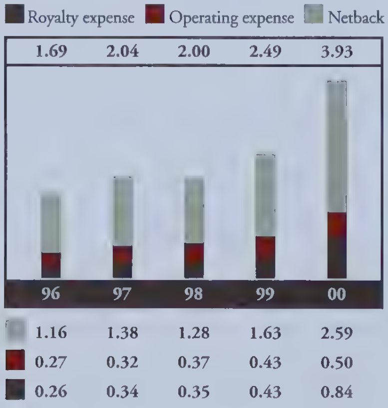
Oil prices began their recovery in late fiscal 1999 with OPEC countries cutting production volumes to support the oil price. Although OPEC has increased output in the current year, higher demand has resulted in continued high prices. The price received for light and medium crude oil increased 80 percent over last year to average $39.48 per barrel in fiscal 2000. Heavy oil prices showed a more dramatic increase, rising 97 percent to $28.98 per barrel.

CRUDE OIL NETBACKS Years ended September 30

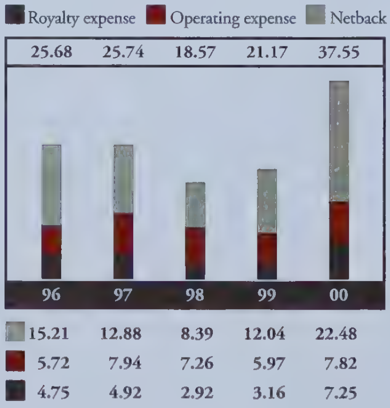
(per Bbl)	2000	1999	% Change
Sales revenue	**$ 37.55**	$ 21.17	77
Royalties	**(7.25)**	(3.16)	129
Operating costs	**(7.82)**	(5.97)	31
Netback	**$ 22.48**	$ 12.04	87
Royalty percentage	**19%**	15%	27
Daily sales volumes (Bpd)			
Light/medium crude oil	**23,672**	22,840	4
Heavy crude oil	**5,354**	2,725	96
Total crude oil	**29,026**	25,565	14

Other oil and gas revenue in fiscal 2000 includes the amortization of settlement payments received on the termination of certain long term natural gas sales contracts, net revenue from straddle plant operations, gains on brokered gas sales and other gains and losses. Most of the increase this year came from straddle plant revenues as a result of improved processing margins between NGL prices and natural gas feedstock prices and increased ethane sales volumes due to plant expansions.

NATURAL GAS AND NGL NETBACKS
($ per Mcf)

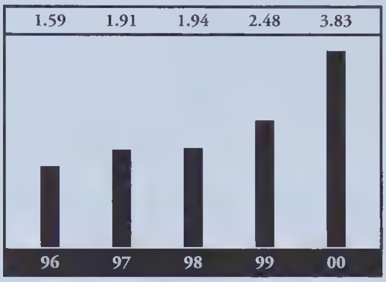


CRUDE OIL NETBACKS
($ per Bbl) (including hedging gains)

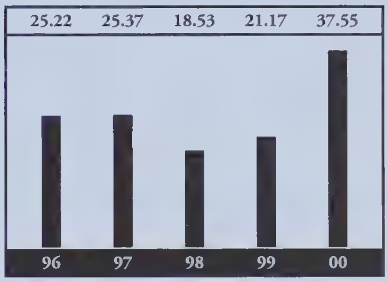


AVERAGE COMPANY PRICES

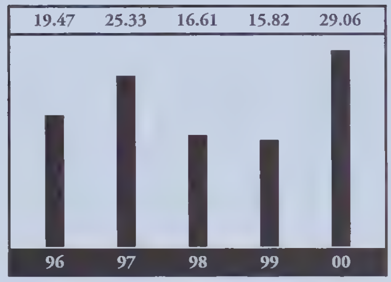
NATURAL GAS
($ per Mcf)



CRUDE OIL
($ per Bbl)



NGL
($ per Bbl)



ROYALTIES Oil and gas royalties, net of the Alberta Royalty Tax Credit (ARTC), have increased 132 percent to $291.8 million from $125.9 million last year as a result of higher product prices. Royalties as a percentage of revenue increased to 21 percent this year from 16 percent last year. In fiscal 2000, the Company was again able to achieve a corporate average gas price in Alberta that was higher than the Alberta Reference Price upon which Alberta gas Crown royalties are based. This has the effect of reducing the effective royalty rate for the Company. Royalties as a percentage of revenue are expected to increase in 2001 since royalty rates rise with higher product prices.

OPERATING EXPENSES Operating expenses increased to $209.4 million this year from $153.6 million last year. On a barrel of oil equivalent basis, operating costs were $3.95 compared to $3.28 last year. Expenses in the latter part of the year were affected by higher initial start-up costs associated with the accelerated heavy oil program and overall industry inflation in the cost of goods and services, as well as the upcoming deregulation of the Alberta electrical power industry. In addition, more active workover, repair and maintenance programs were undertaken this year. Processing fees for gas have increased as some of the new production in northeast British Columbia and the Foothills area is processed through third party facilities. On a barrel of oil equivalent basis, operating costs were also affected by lower than expected production volumes. Operating expenses are expected to remain at about $4.00 per barrel of oil equivalent in fiscal 2001.

GENERAL AND ADMINISTRATIVE EXPENSES General and administrative expenses were $52.9 million in fiscal 2000 compared to $40.7 million in the previous year. As a result of the increased capital program and the acquisition of Ulster, the Company had a higher staff count during fiscal 2000, resulting in higher salaries, benefits and office space requirements. The Company also granted share appreciation rights during the year, resulting in an additional compensation expense accrual of $4.1 million in fiscal 2000. Overhead recoveries on operated properties increased 45 percent from last year as a result of the increased activity undertaken in fiscal 2000.

GENERAL AND ADMINISTRATIVE EXPENSES Years ended September 30

(millions of dollars)	2000	1999	% Change
Gross expense	**$ 73.0**	$ 54.6	34
Operating recoveries	**(20.1)**	(13.9)	45
Net expense	**$ 52.9**	$ 40.7	30
Average cost per Boe			
Gross expense	**$ 1.38**	$ 1.17	18
Operating recoveries	**(0.38)**	(0.30)	27
Net expense	**$ 1.00**	$ 0.87	15

General and administrative expenses are expected to increase to $68 million in fiscal 2001 as a result of increased activity. In addition, an increasingly complex regulatory and public consultation process requires substantially more administrative effort. Certain employee compensation is linked to the current market price of the Company's shares and therefore any significant changes in the trading price of the Company's shares will affect this estimate.

The Company does not capitalize general and administrative expenses or allocate any administrative expenses to operating expenses, except to the extent of the Company's working interest in operated capital expenditure programs where overhead fees have been charged to third parties. The Company does not charge overhead fees on 100 percent owned projects. In addition, the Company does not capitalize the salaries and other expenses of its exploration department as direct capital expenditures. These policies allow the readers of the consolidated financial statements to assess the Company's true administrative expenditures. A significant increase in exploration staff has been required to handle our Frontier activity. Some of these administrative costs will be eligible expenditures under the work proposal programs and will be capitalized as overhead recoveries.

INTEREST EXPENSE Interest expense increased to $58.3 million from $42.5 million last year due to substantially higher debt balances this year as a result of the Ulster acquisition and increased interest rates during the year. The Company did not capitalize any interest related to its oil and gas operations in 2000 or 1999. Interest expense is expected to increase in 2001 as a result of a higher average long term debt balance but with cash flow from operations expected to exceed capital expenditures, debt levels and corresponding interest expense should be reduced over the course of the year.

CURRENT TAXES Current taxes in fiscal 2000 decreased to $7.8 million from $20.5 million last year. Increased exploration and development activities and the acquisition of Ulster resulted in increased deductions for income tax purposes. Current taxes include the federal large corporations tax, provincial capital taxes and provincial resource surcharges. In fiscal 2000, these balances amounted to $10.3 million compared to $6.9 million last year. A current income tax recovery of $2.5 million has been recorded in the current year as a result of a loss carryback for income tax purposes. While capital spending (and corresponding tax deductions) will increase next year, the Company will be spending substantially less than its anticipated cash flow from operations and the Company expects to be currently taxable in fiscal 2001. For example, at a U.S.$25 WTI per barrel crude oil price and a $5.25 per thousand cubic feet natural gas price, current taxes, including capital taxes, would be approximately $33 million in fiscal 2001.

OIL AND GAS TAX POOLS At September 30, 2000

(millions of dollars)		
Canadian Development Expenditures	$	236
Canadian Oil and Gas Property Expenditures		497
Undepreciated Capital Cost		424
Other		42
Total available tax pools	$	1,199

The Company has approximately $1.2 billion in unused tax pools. A portion of these pools are successored, as pools obtained in corporate acquisitions (like the Ulster acquisition) are generally dedicated to sheltering the income from properties held by the acquired company at the time of acquisition.

CASH FLOW FROM CONTINUING OPERATIONS Cash flow from continuing operations was $796.9 million in fiscal 2000 compared to $387.6 million last year. On a barrel of oil equivalent basis, cash flow from continuing operations increased 82 percent to $15.03 in fiscal 2000. The Company's cash flow is available for capital programs and the reduction of long term obligations.

CASH FLOW AND EARNINGS FROM CONTINUING OPERATIONS Years ended September 30

($ per barrel of oil equivalent)		**2000**		1999	% Change
Oil and gas revenues	**$**	**26.74**	$	16.47	62
Royalties		**(5.51)**		(2.69)	105
Operating costs		**(3.95)**		(3.28)	20
		17.28		10.50	65
General and administrative expenses		**(1.00)**		(0.87)	15
Interest		**(1.10)**		(0.91)	21
Current taxes		**(0.15)**		(0.44)	(66)
Cash flow from continuing operations		**15.03**		8.28	82
Depletion and depreciation		**(5.89)**		(5.57)	6
Future site restoration		**(0.35)**		(0.39)	(10)
Deferred taxes		**(4.11)**		(0.90)	357
Earnings from continuing operations	**$**	**4.68**	$	1.42	230

DEPLETION AND DEPRECIATION Depletion and depreciation provided on the unit of production method is based on total proven reserves with conversion of natural gas to oil using their relative energy content of six thousand cubic feet per barrel. As a result of higher finding and development costs, the Company's rate for providing depletion and depreciation of oil and gas assets increased to $5.89 per barrel of oil equivalent from $5.57 last year. It is expected that the rate will increase again in fiscal 2001. Unproved properties are excluded from depletion and depreciation calculations and future development costs of proven undeveloped reserves are included in depletion and depreciation calculations. The Company's unproved properties increased to $375.0 million at September 30, 2000 from $179.0 million last year. The increase is attributable to the nearly 600,000 acres of undeveloped land acquired as part of the Ulster acquisition, the significant increase in expenditures at Crown land sales in fiscal 2000 and expenditures incurred in the Frontier. Future development costs increased from $301.7 million to $340.3 million in fiscal 2000 as a result of the proven undeveloped reserves added as part of the Ulster acquisition and changes in estimates in the Foothills area.

FUTURE SITE RESTORATION The current year provision for future site restoration decreased to $0.35 per barrel of oil equivalent from $0.39 in fiscal 1999 primarily as a result of the estimate of future costs remaining stable while the reserves base increased. The total estimate of the future liability for site restoration on oil and gas properties increased slightly this year to $283.4 million from $267.3 million last year. Increases in the number of wells included in the estimate were offset by reductions in estimates for problem wells. Actual abandonment and reclamation work conducted in the past year has indicated that problems relating to surface casing vent repairs, outside gas migration and production repairs were not as extensive as estimated in the past. On a barrel of oil equivalent basis, the provision for future site restoration is not expected to change significantly in fiscal 2001.

DEFERRED TAXES Deferred taxes on oil and gas operations have increased from fiscal 1999 due to higher pre-tax earnings. The total tax provision as a percentage of pre-tax earnings was 47.6 percent compared to 48.5 percent last year. This year, Crown royalties and production taxes paid were higher than resource allowance claimed. In addition, non-deductible depletion increased in fiscal 2000 as a result of the Ulster acquisition. These factors resulted in an increase in the effective tax rate. However, pre-tax earnings in fiscal 2000 increased 268 percent over fiscal 1999, which meant that large corporations tax and provincial capital taxes and resource surcharges had a smaller effect on the effective tax rate in fiscal 2000 than in fiscal 1999, resulting in an overall reduction in the total effective rate.

EARNINGS FROM CONTINUING OIL AND GAS OPERATIONS Earnings from continuing operations were $248.2 million in fiscal 2000 compared to $66.4 million last year. The 274 percent increase was primarily due to higher product prices and higher sales volumes.

EARNINGS FROM DISCONTINUED PIPELINE OPERATIONS On June 28, 2000, the Company entered into an agreement to sell its 50 percent interest in Federated Pipe Lines Ltd., a pipeline transportation company. The Company received net proceeds on the sale of $102.5 million. A plan of arrangement to dispose of the assets was put into place on March 31, 2000 and operations subsequent to this date are included in the gain on sale of $63.5 million recorded in the third quarter. For the six months ended March 31, 2000, earnings from discontinued operations, net of taxes of $1.5 million, were $1.8 million and cash flow from operations was $4.4 million.

ACCOUNTING CHANGES Effective October 1, 2000, the Company adopted the new Canadian Institute of Chartered Accountants (CICA) accounting recommendations for Accounting for Income Taxes and for Employee Future Benefits. The new recommendations for Accounting for Income Taxes require the adoption of the liability method of tax allocation accounting. Adoption of the recommendations for income taxes will be done on a retroactive basis without restatement of prior periods and will result in an increase in property, plant and equipment of approximately $77 million, an increase in future income tax liabilities of approximately $198 million and a decrease in retained earnings of approximately $121 million. The adjustment is principally due to the Ulster acquisition. In September 2000, the Alberta government announced its intention to reduce general corporate tax rates from 15.5 percent to 8.0 percent over a four year period. This will result in a reduction of future income tax liabilities and a corresponding reduction in future tax expense in the periods in which these rate reductions are enacted.

The new accounting recommendations for Employee Future Benefits modify the requirements for pension costs and obligations and apply these requirements to non-pension benefits. Adoption of this standard will also be done on a retroactive basis without restatement of prior periods as of October 1, 2000 but will not have a material effect on the consolidated assets or results of operations of the Company.

The CICA has also approved a new Handbook section on Earnings Per Share. The new section brings Canadian requirements in line with U.S. and international standards. Under the new standard, the treasury stock method is used instead of the imputed earnings method to determine the dilutive effect of warrants, options and equivalents on per share earnings. Under the treasury stock method, it is assumed that proceeds from the exercise of outstanding stock options are used to purchase common shares at the average market price during the period. Effectively, only "in the money" stock options are included in diluted earnings and cash flow from operations per share calculations. The Company adopted the new recommendations in the fourth quarter of fiscal 2000, restating all prior period per share information to conform with the new recommendations.

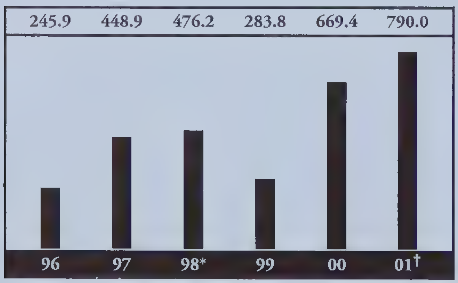
CAPITAL EXPENDITURES Net oil and gas capital expenditures were $669.4 million in fiscal 2000, excluding the Ulster acquisition, and represented 84 percent of cash flow from operations. This compares to $283.8 million in fiscal 1999. The Ulster acquisition resulted in the addition of another $1 billion to property, plant and equipment. The Company replaced 316 percent of its production with proven reserves, after revisions. The capital budget was revised upward twice last year as a result of the higher commodity prices and the associated increased cash flow from operations.

Over the past year, the Company substantially increased its land position North of 60°. In fiscal 2000, the Company entered into work proposals of approximately $334.6 million for interests in 1.6 million net acres in the Mackenzie Delta, the shallow water Beaufort Sea and the Central Mackenzie Valley in the Northwest Territories, and at Eagle Plain in the Yukon Territory. This activity brings the Company's total work proposals to an estimated $376.7 million, most of which required work expenditure deposits of 25 percent which were made by letters of credit. The work expenditure deposits are recoverable as eligible expenditures are made over the next five years at a rate of $1 for every $4 spent. In fiscal 2000, approximately $4.6 million of eligible expenditures were incurred. Other land acquisition activity in 2000 was concentrated in northeast British Columbia, the Foothills and Deep Basin areas, with 495,337 net acres acquired. Over 90 percent of exploration and 60 percent of development capital expenditures were spent on natural gas plays. Over 70 percent of exploration and 50 percent of total capital expenditures were spent in the Frontier, Foothills, northeast British Columbia and Deep Basin areas.

NET CAPITAL EXPENDITURES Years ended September 30

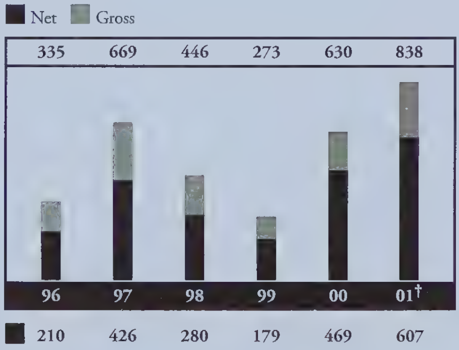
(millions of dollars)	2000	1999	% Change
Exploration drilling and completion	**$ 182.4**	$ 66.8	173
Seismic	**40.4**	25.9	56
Land acquisition and retention	**89.0**	38.3	132
	311.8	131.0	138
Frontier seismic	**15.0**	0.1	–
Frontier land	**16.0**	–	–
	31.0	0.1	–
Development drilling, completion and recompletion	**166.3**	53.9	209
Plant and production facilities	**144.1**	75.0	92
Miscible fluids	**7.2**	3.3	118
	317.6	132.2	140
Total land acquisition, exploration and development activities	**660.4**	263.3	151
Property acquisitions	**15.4**	23.1	(33)
Straddle plant	**–**	4.4	(100)
Corporate	**4.0**	2.6	54
Gross oil and gas capital expenditures	**679.8**	293.4	132
Proceeds on disposition of properties	**(10.4)**	(9.6)	8
Net oil and gas capital expenditures	**669.4**	283.8	136
Discontinued operations	**–**	5.4	(100)
Acquisition of Ulster Petroleums Ltd.	**1,000.7**	–	–
	$ 1,670.1	$ 289.2	478

NET OIL AND GAS CAPITAL EXPENDITURES
(millions of dollars)



* 1998 includes acquisition of Swan Hills interest for $98.8 million
† Budget

WELLS DRILLED FOR OIL AND GAS



† Budget

Net capital expenditures, excluding acquisitions, are expected to increase to $790 million in fiscal 2001. This amount includes approximately $49 million for seismic activity and drilling in the Mackenzie Delta and Eagle Plain areas. In western Canada, the Company will continue a strategy that it started two years ago to shift its exploration focus into deeper and more prospective plays. The Ulster acquisition has helped in accelerating this process as the Company acquired significant production, infrastructure and exploratory lands in the Deep Basin area. In 2001, the Deep Basin program will account for the biggest percentage of the exploration budget. This is a multi-target area with extensive Company interest gas gathering and plant infrastructure. Next to the Deep Basin, the exploration emphasis will be on the Foothills where the Company has identified many multi-zone prospects with large resource potential. Key new areas include Bighorn and Narraway. Together, the Deep Basin and Foothills account for about 46 percent of the total exploration budget. Activities in northeast British Columbia will be reduced compared to previous years, as the 2000 drilling program did not generate the follow-up activities that were anticipated. Exploration programs in the Peace River Arch, central and southern Plains and northern Plains are projected to maintain existing production levels as these areas represent the more mature part of the Western Canada Sedimentary Basin. The Company will also be aggressively growing the heavy oil part of its business in the northern Plains.

FISCAL 2001 CAPITAL BUDGET (BY ACTIVITY)

(millions of dollars)		
Exploration and land	$ 393	50%
Development	343	43%
Frontier exploration	49	6%
Other	5	1%
	$ 790	100%

FISCAL 2001 CAPITAL BUDGET (BY PRODUCT)

(millions of dollars)		
Natural gas	$ 620	78%
Crude oil	165	21%
Other	5	1%
	$ 790	100%

Finding and development costs for total proven reserves, inclusive of the Ulster acquisition and revisions, increased to $9.84 per barrel of oil equivalent (converted at six thousand cubic feet per barrel). The increase in comparison to previous years reflects lower than anticipated gas drilling additions, increased pre-investment costs for land and seismic, drilling delays due to wet weather and a higher goods and services cost environment due to increased industry activity. In addition, strong oil prices provided the incentive to increase spending on heavy oil wells that added production and converted proven undeveloped reserves to proven producing reserves but, as expected, did not add new proven reserves. As well, some well and reservoir performance issues in a number of areas resulted in negative reserve revisions. Finally, in anticipation of the establishment of more stringent generally accepted reserve definitions for the industry, the Company has adopted higher proven and probable reserve confidence levels resulting in some negative reserve revisions. Although the cost pressures will continue in fiscal 2001, reduced land acquisitions and increased activity in the traditionally low finding and development cost areas should reduce finding and development costs next year.

FINDING AND DEVELOPMENT COSTS Years ended September 30

(Boe calculated at 6:1)	2000	1999
Net oil and gas capital expenditures (millions of dollars)	**$ 669.4**	$ 283.8
Less frontier expenditures (millions of dollars)	**(31.0)**	–
Less straddle plant expenditures (millions of dollars)	**–**	(4.4)
	638.4	279.4
Site restoration expenditures (millions of dollars)	**10.1**	6.3
Acquisition of Ulster Petroleums Ltd. (millions of dollars)	**1,000.7**	–
	$ 1,649.2	$ 285.7
Reserve additions before revisions (million Boe)		
Proven	**184.2**	58.4
Proven plus one half probable	**217.9**	72.2
Reserve additions after revisions (million Boe)		
Proven	**167.6**	53.9
Proven plus one half probable	**181.5**	50.5
Finding and development costs before revisions – current year		
Proven	**$ 8.95**	$ 4.89
Proven plus one half probable	**$ 7.57**	$ 3.96
Finding and development costs after revisions – current year		
Proven	**$ 9.84**	$ 5.31
Proven plus one half probable	**$ 9.09**	$ 5.66
Finding and development costs after revisions – three year average		
Proven	**$ 8.50**	$ 6.50
Proven plus one half probable	**$ 8.15**	$ 6.22
Finding and development costs after revisions – five year average		
Proven	**$ 7.74**	$ 5.72
Proven plus one half probable	**$ 7.39**	$ 5.03

FINANCIAL RESOURCES AND LIQUIDITY The Company's financial obligations increased by $614.8 million in fiscal 2000. Long term debt increased from $546.1 million at September 30, 1999 to $1,126.9 million at September 30, 2000 while the net working capital deficiency (excluding the current portion of long term debt) increased from $29.0 million to $63.0 million. The increase in long term debt was largely a result of the Ulster acquisition. The increase is made up of $331.7 million of new debt, net of $1.3 million in transaction costs, the assumption of $312.2 million of existing Ulster debt, the disposition of $60.2 million of Federated debt at March 31, 2000 and the repayment of $5.8 million of Federated debt prior to disposition. The increase in debt as a result of changes in the Canadian/U.S. exchange rate was $1.6 million to September 30, 2000. The Company's debt arrangements are discussed in detail in note 4 to the accompanying consolidated financial statements.

On May 16, 2000, in connection with the Ulster acquisition, the Company arranged a new $500 million syndicated credit facility and $400 million in bridge facilities with a Canadian chartered bank. On July 18, 2000, the Company issued $175.0 million of 7.25 percent unsecured, non-redeemable notes, maturing July 18, 2005, under a $500.0 million medium term note program pursuant to a short form shelf prospectus dated June 28, 2000. At September 30, 2000, the medium term notes were rated "A–" by CBRS Inc. and "BBB (high)" by Dominion Bond Rating Service Limited.

On October 31, 2000, Standard & Poor's and CBRS Inc. announced that they have combined operations in Canada. A process is underway to harmonize all ratings assigned by CBRS with the Standard & Poor's framework, which includes the translation of all ratings onto the Standard & Poor's ratings scale. Standard & Poor's has given Anderson Exploration's medium term note program a "BBB+" senior unsecured debt rating. Standard & Poor's "BBB+" rating reflects an equivalent credit quality to CBRS's "A–" rating. The following financial ratios are provided in connection with the Company's medium term note program:

Interest coverage on long term debt	
Earnings[(a)]	10.0
Cash flow from operations[(b)]	14.4
Net asset coverage on long term debt[(c)]	
Before deduction of deferred income taxes	3.1
After deduction of deferred income taxes	2.4

(a) Interest coverage on long term debt on an earnings basis is equal to earnings before interest on long term debt and taxes divided by interest on long term debt for the 12 months ended September 30, 2000.

(b) Interest coverage on long term debt on a cash flow from operations basis is equal to cash flow from operations before interest on long term debt and cash taxes divided by interest on long term debt for the 12 months ended September 30, 2000.

(c) Net asset coverage on long term debt is equal to total assets less liabilities (excluding long term debt) divided by long term debt at September 30, 2000. Long term debt includes the current portion of long term debt.

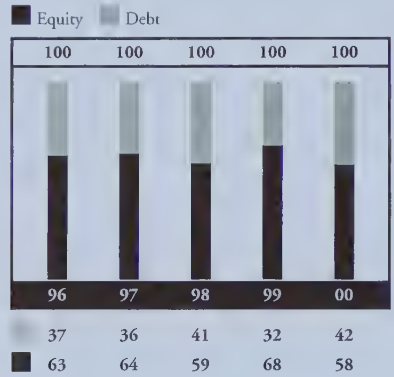
(d) On June 28, 2000, the Company sold its 50 percent interest in the shares of Federated. Interest coverage ratios of the Company excluding the results of Federated are as follows:

Interest coverage on long term debt:	
Earnings	9.1
Cash flow from operations	14.8

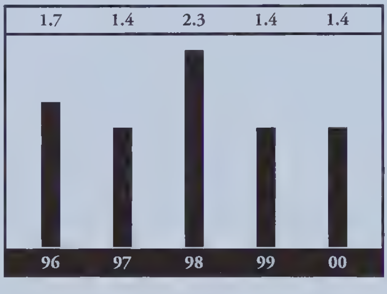
Proceeds of $49.4 million were received on the issue of 3.0 million common shares under the employee stock savings plan and stock option plan. The Company repurchased 2.3 million common shares in fiscal 2000 through its Normal Course Issuer Bid program at an average price of $16.81 per share and a total cost of $38.7 million. Subsequent to year end, the Company purchased an additional 1.0 million shares to bring the total purchase under the bid to 3.3 million common shares at an average price of $19.93. At September 30, 2000, the Company had unused long term lines of credit of $586 million. On October 4, 2000, the Series A senior U.S. dollar notes in the amount of U.S.$15 million were repaid. On October 31, 2000, the oil indexed debentures in the amount of $200 million were repaid. The repayments were financed using existing long term revolving credit facilities. No other debt repayments are required in fiscal 2001. The Company uses interest rate swaps to effectively fix the interest rate on a portion of outstanding debt. The swaps are described in the notes to the consolidated financial statements.

Cash flow from operations covered interest expense 14.4 times in 2000 compared to 10.0 times in 1999. Long term debt at year end was 1.4 times 2000 cash flow from operations, the same as in 1999. In fiscal 2001, capital expenditures are expected to be less than cash flow from operations and the ratio of long term debt to cash flow from operations is expected to decrease to less than 1.0.

DEBT TO DEBT PLUS EQUITY
at September 30 (%)



LONG TERM DEBT TO
CASH FLOW RATIO
at September 30



SHARE INFORMATION The Company's common shares have been listed for trading on The Toronto Stock Exchange since July 12, 1988 under the symbol "AXL." At September 30, 2000, there were 131.5 million common shares outstanding. During 2000, 4.8 million common shares were issued with respect to the purchase of Ulster, 3.0 million common shares were issued under the employee stock option and stock savings plans and 2.3 million common shares were repurchased pursuant to the Company's Normal Course Issuer Bid. These shares were cancelled and returned to treasury. The Company's market capitalization at September 30, 2000 was $4.3 billion. Trading in the common shares is very liquid with an average of 594,400 common shares trading per trading day, representing a 118 percent turnover ratio in fiscal 2000.

SHARE PRICE

	1996 Year	1997 Year	1998 Year	1999 Year	2000 Q1	2000 Q2	2000 Q3	2000 Q4	2000 Year
High	15.25	20.25	19.40	22.60	**20.00**	**21.15**	**29.40**	**33.95**	**33.95**
Low	11.62	13.70	12.50	11.60	**14.75**	**16.10**	**18.25**	**22.65**	**14.75**
Close	13.70	17.20	16.00	19.40	**17.25**	**21.00**	**26.90**	**32.90**	**32.90**
Volume (000)	87,963	107,697	100,295	134,580	**28,542**	**32,151**	**48,307**	**40,787**	**149,787**

Anderson Exploration's Normal Course Issuer Bid expired on November 30, 2000. The Company filed a Notice of Intention to make a new Normal Course Issuer Bid in fiscal 2001. The Company believes that when the underlying value of its common shares is not reflected in market prices, the share purchase program provides value by reducing the number of common shares outstanding. Increases in commodity prices have led to substantial increases in cash flow from operations and a corresponding reduction in long term debt. We expect this situation to continue in the coming fiscal year, which would provide the funding for the issuer bid. At such time as common shares become available at prices which make purchase of them an appropriate use of the Company's funds, the Company will make normal course purchases through the facilities of The Toronto Stock Exchange. While Anderson Exploration is not required to purchase any shares under the program, it may acquire up to five percent of the common shares that are outstanding at the time the bid is filed.

BUSINESS RISKS Natural gas and crude oil exploration, development, production and marketing operations involve a number of business risks including the uncertainty of finding new reserves, the instability of commodity prices, operational risks, the cost of capital available to fund exploration and development programs, regulatory issues and taxation and the requirements of new environmental laws and regulations. The Company manages these risks by employing competent professional staff, following sound operating practices and utilizing cash flow from operations and the prudent issue of equity to fund a significant portion of capital expenditures so that debt does not become a burden. With increased activity in the oil and gas industry during the last year, the job market for industry professionals is becoming tighter. The Company offers competitive compensation packages to enable it to attract and retain highly competent professional staff.

The Company generates its exploration prospects internally. Extensive geological, geophysical, engineering and environmental analyses are performed before committing to the drilling of new prospects. These analyses are used to ensure a suitable balance between risk and reward. Technological advances provide new methods of economically increasing the recovery of hydrocarbons. The Company seeks out and employs new methodologies to maximize product recoveries and reduce costs.

Commodity prices are influenced by local and worldwide supply and demand, competition, the U.S. dollar exchange rate, transportation, political stability and seasonal changes in demand resulting from weather patterns in the Company's marketing areas. The value of the Canadian dollar, which is influenced by economic and political factors, affects most of the Company's crude oil and natural gas sales. To reduce the impact of these factors, the Company maintains a balanced portfolio of sales contracts. The Company does enter into physical contracts for the sale of natural gas at fixed prices and terms; however, other forms of hedging contracts are subject to approval by the Board of Directors. Anderson Exploration's current policy is that it will not hedge natural gas or crude oil prices.

The Company has fixed the rate of interest on approximately 46 percent of its long term debt obligations at an average effective rate of approximately 7.2 percent. Between 1996 and 1998, the Company fixed the rate of interest on $253.0 million of its outstanding bank loans through swap agreements at an average rate of 6.94 percent. The agreements mature at various dates between 2001 and 2007. In June 2000, the Company filed a short form shelf prospectus in connection with its medium term note program and has issued $175 million of medium term notes at 7.25 percent. The remaining outstanding senior notes assumed on the Ulster acquisition, currently amounting to U.S.$60 million, have an effective interest rate of 7.5 percent. In addition to fixing the interest rate, the medium term note program and senior U.S. dollar notes allow the Company to manage debt maturities. The senior U.S. dollar notes provide a small natural hedge against U.S. dollar receipts.

Historically, regulatory issues and taxation have had a significant impact on the oil and natural gas industry. However, with the deregulation of the industry beginning in 1985 and stable taxation levels, there is currently a reasonable operating environment in Canada for financially healthy companies. The potential exists for this environment to change due to changes in taxation and energy policy. Tax rate reductions proposed in the last federal budget and the "pre-election" economic statement currently exclude the resource sector. The Canadian Association of Petroleum Producers is continuing its discussions with federal finance officials on this issue. Previously announced reductions in Alberta provincial tax rates are expected to be implemented and should benefit the resource sector.

On January 1, 2001, the Alberta government will proceed with the deregulation of the electrical power industry. Electrical contracts will be "unbundled" and power supply costs will be separated from transmission and distribution costs. All large industrial consumers will be required to procure their own electrical power supply. Anderson Exploration has chosen to manage its power purchases through a retailer, but could also have some supply from on site generation and some purchases from independent power producers. The Company may chose to manage a portion of its portfolio through the use of financial instruments in addition to physical contracts. The tight supply and demand associated with the start up of the new system may result in substantially higher power costs. Operators will be responsible for the procurement of power on behalf of themselves and their partners, at least initially. While the Company operates the majority of its oil and gas operations, it will rely on its partners to secure electricity on a reliable and cost effective basis for those properties it does not operate.

The industry is subject to extensive regulations imposed by governments related to the protection of the environment. Environmental legislation in western Canada has undergone major revisions. Environmental standards and compliance are more stringent. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and has instituted a series of controls and procedures with respect to environmental protection. The estimated liability for future abandonment and restoration costs is reviewed annually and is recorded in accordance with accounting recommendations. Total future costs are estimated to be $283.4 million, of which $68.4 million has been recorded as a liability to date. The Company is committed to managing this liability and will take full advantage of new technology during the drilling, producing and abandoning phases of its operations to keep these costs as low as possible.

SENSITIVITIES The Company's earnings and cash flow from operations are highly sensitive to changes in factors that are beyond its control. An estimate of the Company's sensitivities to changes in commodity prices, exchange rates and interest rates is summarized below.

	Cash Flow from Operations		Earnings	
	Millions	Per Share	Millions	Per Share
$0.10/Mcf in the price of natural gas	$ 21	$ 0.16	$ 12	$ 0.09
U.S.$1.00/Bbl in the WTI crude oil price	$ 20	$ 0.15	$ 12	$ 0.09
U.S.$0.01 in the U.S./Cdn. exchange rate	$ 6	$ 0.05	$ 4	$ 0.03
1% in short term interest rates	$ 2	$ 0.02	$ 2	$ 0.02

BUSINESS PROSPECTS World demand for petroleum has grown unabated since about 1993 when North America and most other parts of the world began their current long period of economic expansion. From 1993 to 1999, world petroleum demand grew at an average rate of about 1.9 percent per annum. Even during 1998, when a number of the developing southeast Asian countries experienced financial problems, petroleum demand continued to grow. On the supply side, the vast resources of OPEC more than capably met the growing world demand during the 1990s. Based on current production levels, it is estimated that most of OPEC's previously unused capacity, with the exception of Saudi Arabia, has now been utilized. Based on the current forecast of world demand growth of 1.5 percent to 2.5 percent per year through 2001, oil stocks should remain relatively tight. If the world economy continues to expand, it is easy to envision a scenario of sustained high oil prices into 2001. The risk is that U.S.$30 oil may slow down the world economy, reduce crude demand and stimulate non-OPEC supply. OPEC is publicly supporting a long term band of approximately U.S.$24 – U.S.$30 WTI. Even with OPEC's intention to stabilize the oil markets, prices in 2001 will be volatile given the tight demand and supply fundamentals.

Natural gas is a North American continental commodity. Gas prices in North America are influenced primarily by supply and demand fundamentals in the United States. Years of low gas prices have resulted in domestic supply failing to keep pace with increased demand. Most of this increased demand has been met by larger imports from Canada. The uncertainty around U.S. deliverability has caused nervousness in the markets, and resulted in gas trading at the highest summer prices ever seen in North America. Winter prices will be influenced by actual winter weather. Assuming a return to a normal winter in 2001, we could see very high price spikes during cold periods. If U.S. productivity does not increase this winter, there will be less gas in storage at the start of the 2001 fill season even if there is a warm winter, translating into exceptional 2001 summer gas prices.

Approximately 66 percent of the Company's remaining proven reserves are natural gas. The Company's natural gas sales portfolio in fiscal 2000 had approximately 79 percent of sales priced in the Alberta and British Columbia spot markets, increasing to 84 percent in fiscal 2001. The Company is well positioned to capitalize on the strong gas prices expected next year. Increased cash flow resulting from the high prices will be used to fund the fiscal 2001 capital program and to pay down debt incurred with the Ulster acquisition.

In fiscal 2000, Anderson Exploration achieved record cash flow from operations, cash flow from operations per share, earnings and earnings per share, as well as the highest production levels in the Company's history. Record high prices for natural gas and crude oil fuelled these excellent results.

MANAGEMENT'S REPORT

Management is responsible for the preparation of the consolidated financial statements and the consistent presentation of all other financial information in this annual report.

Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. Their report is presented below. The Audit Committee of the Board of Directors, composed of four independent directors, meets with management and the external auditors quarterly to discuss financial reporting issues and to review interim and annual financial statements prior to their release. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

J.C. Anderson

J.C. Anderson
Chairman & Chief Executive Officer
November 15, 2000

D.G. Scobie

David G. Scobie
Senior Vice President & Chief Financial Officer

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Anderson Exploration Ltd. as at September 30, 2000 and 1999 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at September 30, 2000 and 1999 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
November 15, 2000

CONSOLIDATED BALANCE SHEETS

SEPTEMBER 30 (stated in millions of dollars)	2000	1999
ASSETS		
Current assets		
Accounts receivable	$ 227.7	$ 125.0
Inventories	17.8	11.2
	245.5	136.2
Property, plant and equipment (note 3)	3,728.1	2,470.0
	$ 3,973.6	$ 2,606.2
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness	$ 32.4	$ 14.7
Accounts payable and accrued liabilities	272.9	136.2
Taxes payable	3.2	14.3
Current portion of long term debt	–	0.9
	308.5	166.1
Long term debt (note 4)	1,126.9	545.2
Other credits (note 5)	133.6	136.7
Deferred income taxes	841.1	622.4
	2,410.1	1,470.4
Shareholders' equity		
Share capital (note 6)	905.3	791.1
Retained earnings	658.2	344.7
	1,563.5	1,135.8
	$ 3,973.6	$ 2,606.2

See accompanying notes to consolidated financial statements.

On behalf of the Board:

J.C. Anderson

Director

Director

CONSOLIDATED STATEMENTS OF EARNINGS

YEARS ENDED SEPTEMBER 30 (stated in millions of dollars, except per share amounts)	2000	1999
Revenues		
Oil and gas	$ 1,417.1	$ 770.9
Royalties, net of ARTC of $0.7 million (1999 – $1.5 million)	(291.8)	(125.9)
	1,125.3	645.0
Expenses		
Operating	209.4	153.6
Depletion and depreciation	312.0	260.7
General and administrative	52.9	40.7
Interest (including $58.3 million on long term debt; 1999 – $41.9 million)	58.3	42.5
Future site restoration	18.6	18.5
	651.2	516.0
Earnings from continuing operations before taxes	474.1	129.0
Taxes (note 8)		
Current	7.8	20.5
Deferred	218.1	42.1
	225.9	62.6
Earnings from continuing operations	248.2	66.4
Earnings from discontinued operations (note 2)	65.3	4.0
Earnings	$ 313.5	$ 70.4
Basic earnings per common share		
From continuing operations	$ 1.95	$ 0.54
From discontinued operations	0.51	0.03
	$ 2.46	$ 0.57
Diluted earnings per common share (note 7)		
From continuing operations	$ 1.92	$ 0.54
From discontinued operations	0.51	0.03
	$ 2.43	$ 0.57
Weighted average number of common shares outstanding (millions)	127.4	124.1

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

YEARS ENDED SEPTEMBER 30 (stated in millions of dollars)	2000	1999
Retained earnings, beginning of year	$ 344.7	$ 274.3
Earnings	313.5	70.4
Retained earnings, end of year	$ 658.2	$ 344.7

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED SEPTEMBER 30 (stated in millions of dollars, except per share amounts)	2000	1999
Cash provided by (used in):		
Operations		
Earnings from continuing operations	**$ 248.2**	$ 66.4
Add (deduct) non-cash items:		
Depletion and depreciation	**312.0**	260.7
Future site restoration	**18.6**	18.5
Deferred taxes	**218.1**	42.1
Other	**–**	(0.1)
Cash flow from continuing operations	**796.9**	387.6
Cash flow from discontinued operations (note 2)	**4.4**	8.0
Cash flow from operations	**801.3**	395.6
Change in deferred revenue	**(10.4)**	(10.6)
Change in non-cash working capital related to:		
– continuing operations (note 9)	**(17.6)**	21.1
– discontinued operations (notes 2 and 9)	**0.9**	1.0
	774.2	407.1
Investments		
Additions to property, plant and equipment	**(679.8)**	(293.4)
Proceeds on disposition of property, plant and equipment	**10.4**	9.6
Acquisition of Ulster Petroleums Ltd. (note 2)	**(550.1)**	–
Proceeds on disposition of Federated Pipe Lines Ltd. (note 2)	**103.3**	–
Site restoration expenditures	**(10.1)**	(6.3)
Change in non-cash working capital related to investments (note 9)	**(2.0)**	4.8
Discontinued operations (notes 2 and 9)	**(0.2)**	(8.0)
	(1,128.5)	(293.3)
Financing		
Increase (decrease) in long term debt	**331.7**	(150.3)
Issue of common shares	**49.4**	42.7
Repurchase of common shares	**(38.7)**	–
Discontinued operations (note 2)	**(5.8)**	–
	336.6	(107.6)
Increase (decrease) in cash	**(17.7)**	6.2
Cash position, beginning of year	**(14.7)**	(20.9)
Cash position, end of year	**$ (32.4)**	$ (14.7)
Basic cash flow from operations per common share		
From continuing operations	**$ 6.26**	$ 3.13
From discontinued operations	**0.03**	0.06
	$ 6.29	$ 3.19
Diluted cash flow from operations per common share (note 7)		
From continuing operations	**$ 6.17**	$ 3.12
From discontinued operations	**0.03**	0.06
	$ 6.20	$ 3.18

See accompanying notes to consolidated financial statements.

Cash position includes cash net of current bank indebtedness. Current bank indebtedness includes outstanding cheques.

The Ulster acquisition amount represents the value assigned to property, plant and equipment of $1,000.7 million less share consideration of $103.5 million and debt and non-cash working capital deficiency of $347.1 million assumed from Ulster. The Federated disposition amount represents net proceeds of $102.5 million plus bank indebtedness of $0.8 million assumed by the purchaser.

YEARS ENDED SEPTEMBER 30, 2000 AND 1999 (tabular amounts in millions of dollars, unless otherwise stated)

Anderson Exploration Ltd. ("Anderson Exploration" or "the Company") is engaged in the acquisition, exploration, development and production of oil and gas resources in western and northern Canada. The consolidated financial statements include the accounts of Anderson Exploration and its wholly owned subsidiaries and have been prepared in accordance with generally accepted accounting principles in Canada.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) JOINT INTEREST OPERATIONS

A significant proportion of the Company's oil and gas exploration, development and production activities are conducted with others and accordingly the accounts reflect only the Company's proportionate interest in such activities.

(b) INVENTORIES

Inventories are stated at the lower of cost and net realizable value. Cost is determined using the specific item or average cost method.

(c) PROPERTY, PLANT AND EQUIPMENT

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all costs relative to the exploration for and development of oil and gas reserves are capitalized into cost centres on a country by country basis. Capitalized costs include lease acquisitions, geological and geophysical costs, lease rentals on non-producing properties, costs of drilling productive and non-productive wells and plant and production equipment costs. General and administrative costs are not capitalized, except to the extent of the Company's working interest in operated capital expenditure programs to which overhead fees have been charged under standard industry operating agreements. Overhead fees are not charged on 100 percent owned projects. Proceeds received from disposals of oil and gas properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

Depletion of oil and gas properties and depreciation of plant and production equipment are provided on the unit of production method based on total proven reserves before royalties as estimated by Company engineers. Natural gas sales and reserves are converted to equivalent units of crude oil using their relative energy content. Buildings and other equipment are depreciated over their useful lives using the declining balance and straight line methods at rates varying from five percent to 40 percent per annum.

The Company applies a ceiling test to capitalized oil and gas property costs to ensure that such costs do not exceed the estimated future net revenues from production of proven reserves, at prices and operating costs in effect at the balance sheet date, plus the cost of unevaluated properties less management's estimate of impairment. The test also provides for estimated future administrative overhead, financing costs and taxes.

(d) FUTURE SITE RESTORATION COSTS

Provisions for future site restoration costs are made over the life of the Company's oil and gas properties using the unit of production method and established reserves. Costs are based on engineering estimates considering current regulations, costs and industry standards. Actual expenditures incurred are applied against deferred future site restoration costs.

(e) STOCK BASED COMPENSATION PLANS

Consideration received from employees or directors on the exercise of stock options under the employee stock option plan and the purchase of stock under the employee stock savings plan is recorded as share capital. The Company matches employee contributions to the stock savings plan and these cash payments are recorded as compensation expense.

Obligations for cash payments under the share appreciation rights plan are accrued as compensation expense over the vesting period of the rights. Changes in the share price, up or down, will change the compensation expense and are recognized prospectively when they occur.

(f) INCOME TAXES

The Company follows the tax allocation method of accounting for income taxes. Under this method, deferred income taxes are recorded to the extent that taxable income otherwise determined is adjusted by timing differences.

New recommendations issued in 1997 by the Canadian Institute of Chartered Accountants will be adopted effective October 1, 2000.

(g) REVENUE RECOGNITION

Settlement payments received for restructuring or terminating long term natural gas sales contracts are recognized as revenue over the remaining period of the contracts or over the life of the reserves associated with the contracts.

(h) FOREIGN CURRENCY TRANSLATION

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date while non-monetary assets and liabilities are translated at historical rates of exchange. Revenues and expenses are translated at monthly average rates of exchange. Translation gains and losses are included in earnings except for unrealized gains and losses on long term monetary items which are deferred and amortized to earnings over their remaining term.

(i) HEDGING

Amounts received or paid under interest rate swaps are recognized in interest expense on an accrual basis. The fair values of the interest rate swap contracts are not recorded in the balance sheet.

(j) PER SHARE AMOUNTS

Basic earnings per common share and cash flow from operations per common share are computed by dividing earnings and cash flow from operations by the weighted average number of common shares outstanding for the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments, in accordance with new standards approved by the Canadian Institute of Chartered Accountants.

(k) USE OF ESTIMATES

Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

2. CORPORATE ACQUISITION AND DISPOSITION

(a) ACQUISITION OF ULSTER PETROLEUMS LTD.

On May 17, 2000, the Company acquired all the outstanding shares of Ulster Petroleums Ltd. ("Ulster"), an oil and gas production company. The consideration given for each Ulster share was $13.10, made up of $11.00 cash and 0.09655 of an Anderson Exploration common share based on Anderson Exploration's closing price of $21.75 per share on the offer date. The transaction has been accounted for using the purchase method with the results of operations included in these financial statements from the date of acquisition. Details of the acquisition are as follows:

Net assets acquired, at assigned values:		
Property, plant and equipment	$	1,000.7
Working capital deficiency		(32.1)
Long term debt assumed		(312.2)
	$	656.4
Purchase price:		
Cash	$	542.2
Common shares (4,758,727 shares)		103.5
Transaction costs		10.7
	$	656.4

(b) DISPOSITION OF FEDERATED PIPE LINES LTD.

On June 28, 2000, the Company entered into an agreement to sell its 50 percent interest in Federated Pipe Lines Ltd. ("Federated"), a pipeline transportation company. The Company received net proceeds on the sale of $102.5 million, which were used to reduce debt related to the acquisition of Ulster.

The Company's proportionate interest in the results of operations of Federated are shown as discontinued operations in the consolidated statements of earnings and cash flows. The carrying values of the assets and liabilities attributable to the discontinued operations and included in the consolidated balance sheet at September 30, 1999 were as follows:

Current assets	$	3.6
Property, plant and equipment		102.8
Current liabilities		(3.7)
Long term debt		(65.0)
Other		(0.5)
Net assets	$	37.2

For the six months ended March 31, 2000, revenues from discontinued operations were $16.7 million, earnings were $1.8 million (net of taxes of $1.5 million) and net capital expenditures were $0.1 million. Results of discontinued operations subsequent to this date were included in the gain on sale of $63.5 million (net of taxes of $1.6 million), as a plan of arrangement to dispose of the assets existed at March 31, 2000.

3. PROPERTY, PLANT AND EQUIPMENT

	2000		1999	
	Cost	**Accumulated depletion and depreciation**	Cost	Accumulated depletion and depreciation
Oil and gas properties, including plant and production equipment	**$ 6,440.0**	**$ (2,743.1)**	$ 4,777.7	$ (2,436.1)
Buildings, land and other	**83.9**	**(52.7)**	73.4	(47.8)
Discontinued operations (note 2)	–	–	155.9	(53.1)
	$ 6,523.9	**$ (2,795.8)**	$ 5,007.0	$ (2,537.0)
Net book value		**$ 3,728.1**		$ 2,470.0

At September 30, 2000, oil and gas properties included $375.0 million (1999 – $179.0 million) relating to unproved properties which have been excluded from depletion and depreciation calculations. Future development costs of proven undeveloped reserves of $340.3 million (1999 – $301.7 million) are included in depletion and depreciation calculations.

At the balance sheet dates, the Company had substantial surpluses in its ceiling tests using balance sheet date prices.

4. LONG TERM DEBT

	2000 Balance outstanding	2000 Interest rate*	1999 Balance outstanding	1999 Interest rate*
Continuing operations				
Bank loans	**$ 385.9**	**6.68%**	$ 27.2	5.30%
Bank loans subject to swaps	**253.0**	**6.94%**	253.0	6.69%
Medium term notes, maturing July 2005	**175.0**	**7.25%**	–	
Senior U.S. dollar notes, maturing October 2000 to October 2006 (U.S.$75.0 million)	**113.0**	**7.44%**	–	
Oil indexed debentures, maturing October 2000	**200.0**	**8.26%**	200.0	8.26%
	1,126.9		480.2	
Discontinued operations (note 2)				
Bank loans	–		55.1	5.39%
9.54% sinking fund debentures, maturing October 2002	–		10.8	9.54%
Less current portion	–		(0.9)	
	–		65.0	
	$ 1,126.9		$ 545.2	

* As at September 30.

The Company has a $500 million syndicated revolving credit facility with an extendible 364 day revolving period and a six year term period. Advances under the facility can be drawn in either Canadian or U.S. funds. The facility bears interest at the bank's prime lending rate, banker's acceptance rates plus applicable margins or U.S. LIBOR rates plus applicable margins.

The Company has another syndicated revolving credit facility that was arranged in May 2000 to finance the acquisition of Ulster (note 2). The facility is made up of three separate components. Tranche A is a committed 364 day $100 million bridge facility available by way of a single draw. Tranche B is a committed 18 month $300 million bridge facility available by way of a single draw. Tranche C is a committed $500 million 364 day revolving credit facility, followed by a committed two year term period. In July 2000, the full amount of Tranche A and $75 million of Tranche B were repaid with proceeds from the issue of medium term notes. Tranche A is no longer available and Tranche B has been reduced to $225 million. Advances under the facility can be drawn in either Canadian or U.S. funds. The facility bears interest at the bank's prime lending rate, bankers' acceptance rates plus applicable margins or U.S. Libor rates plus applicable margins.

The Company has fixed the rate of interest on $253.0 million of its bank loans through swap agreements at an average rate of 6.94 percent. These agreements mature at various dates as shown below:

Amount	Interest rate*	Maturity date
$ 35.0	7.36%	September 2001
32.5	6.66%	October 2001
53.0	6.05%	November 2001
7.5	6.80%	October 2002
40.0	7.32%	February 2007
30.0	7.53%	March 2007
30.0	7.32%	June 2007
25.0	6.85%	July 2007
$ 253.0	6.94%	

* Includes margin.

On June 29, 2000, the Company filed a short form shelf prospectus in connection with a two year medium term note program. Medium term notes may be issued from time to time in an aggregate principal amount of up to $500 million and are offered at prices and contain such other terms as may be determined at the time of issue. On July 18, 2000, the Company issued $175 million of 7.25 percent unsecured, non-redeemable notes maturing July 18, 2005 pursuant to the program. At September 30, 2000, these medium term notes were rated "A–" by CBRS Inc. and "BBB (high)" by Dominion Bond Rating Service Limited.

The senior U.S. dollar notes were assumed on the acquisition of Ulster (note 2). The senior notes are denominated in U.S. dollars and were issued in October 1995 in three series as follows:

Series A	7.23%, due in total in October 2000	U.S.$15.0
Series B	7.42%, due in October 2005, annual principal repayments of U.S.$5.8 million begin in October 2001	29.0
Series C	7.57%, due in October 2006, annual principal repayments of U.S.$10.3 million begin in October 2004	31.0
		U.S.$75.0

The bank loans, medium term notes and senior U.S. dollar notes are unsecured and rank equally with one another and are subject to the maintenance of certain financial ratios.

The oil indexed debentures bear interest at a fixed rate of 5.0 percent per annum plus a variable rate of up to 16.8 percent per annum based upon the average price of crude oil. The effective rate of interest on the debentures has been fixed to maturity at 8.26 percent by an unsecured interest rate swap agreement.

The Company has a $100 million operating line of credit, of which $14.7 million was unused at September 30, 2000. The operating line is being used to support outstanding letters of credit associated with the Company's work proposals in northern Canada (note 12).

It is anticipated that the revolving credit facilities (other than the bridge facilities) will be extended. If this is the case, the aggregate amount of payments estimated to be required in each of the next five years are $222.6 million in 2001, $232.7 million in 2002, $8.7 million in 2003, $8.7 million in 2004 and $199.3 million in 2005. If the revolving credit facilities are not extended, the payments would be $222.6 million in 2001, $296.1 million in 2002, $107.0 million in 2003, $72.1 million in 2004 and $262.7 million in 2005. The payments in 2001 consist of the Series A senior U.S. dollar notes repaid on October 4, 2000 and the oil indexed debentures repaid on October 31, 2000. The payments were financed using existing long term revolving credit facilities and so were not classified as current liabilities in these consolidated financial statements.

5. OTHER CREDITS

	2000	1999
Continuing operations		
Deferred future site restoration costs	$ **68.4**	$ 60.0
Deferred revenue	**59.7**	70.0
Pension accrual (note 10)	**5.5**	5.6
	133.6	135.6
Discontinued operations (note 2)	**–**	1.1
	$ **133.6**	$ 136.7

Site restoration involves the surface clean-up and reclamation of well sites and field production facilities to ensure they can be safely returned to appropriate land uses. In addition, certain plant facilities will require decommissioning which will involve dismantling of facilities as well as the decontamination and reclamation of these lands. Total estimated future costs, given the current inventory of wells and facilities, are approximately $283.4 million, of which $68.4 million has been accrued to date.

6. SHARE CAPITAL

Authorized:

Common shares: unlimited

Preferred shares: unlimited

Junior preferred shares, redeemable, participating: unlimited

Issued:

	2000		1999	
	Number of shares	**Amount (millions)**	Number of shares	Amount (millions)
Common shares				
Balance, beginning of year	**126,030,334**	**$ 637.6**	123,260,352	$ 594.9
Issued for cash on exercise of stock options	**2,857,210**	**45.3**	2,553,155	39.2
Issued for cash under employee stock savings plan	**183,793**	**4.1**	216,827	3.5
Issued on acquisition of Ulster	**4,758,727**	**103.5**	–	–
Repurchase of shares under Normal Course Issuer Bid	**(2,303,138)**	**(11.7)**	–	–
Balance, end of year	**131,526,926**	**778.8**	126,030,334	637.6
Contributed surplus				
Balance, beginning of year		**153.5**		153.5
Repurchase of shares under Normal Course Issuer Bid		**(27.0)**		–
Balance, end of year		**126.5**		153.5
	131,526,926	**$ 905.3**	126,030,334	$ 791.1

The Company has an employee stock option plan under which both employees and directors are eligible to receive grants. On September 30, 2000, 6,769,320 common shares were reserved for issuance under the plan. Options granted under the plan generally have a term of five years to expiry and vest equally over a three year period starting on the first anniversary date of the grant. The exercise price of each option equals the market price of the Company's common shares on the date of the grant. At September 30, 2000, 6,466,771 options with exercise prices between $13.15 and $32.90 were outstanding and exercisable at various dates to the year 2005.

	2000		1999	
	Number of options	**Weighted-average exercise price**	Number of options	Weighted-average exercise price
Stock options outstanding, beginning of year	**7,423,564**	**$ 15.71**	7,647,502	$ 15.95
Granted	**2,109,600**	**19.35**	2,595,800	14.68
Exercised	**(2,857,210)**	**15.87**	(2,553,155)	15.35
Cancelled	**(209,183)**	**16.16**	(266,583)	15.93
Stock options outstanding, end of year	**6,466,771**	**$ 16.81**	7,423,564	$ 15.71
Exercisable at year end	**2,000,936**	**$ 16.05**	2,560,734	$ 15.95

	Options outstanding			Options exercisable	
Range of exercise prices	Options outstanding	Weighted-average remaining term (years)	Weighted-average exercise price	Options exercisable	Weighted-average exercise price
Under $15.00	2,137,320	3.2	$ 14.46	613,820	$ 14.49
$15.00 to 16.99	1,459,201	2.5	16.33	693,099	16.34
$17.00 to 18.99	798,950	2.0	17.06	662,650	17.03
Over $19.00	2,071,300	4.5	19.47	31,367	19.40
	6,466,771	3.3	$ 16.81	2,000,936	$ 16.05

In 1999, the employee stock option plan was amended to give the Board of Directors the discretion to attach share appreciation rights to stock options granted after February 10, 1999. Share appreciation rights give the holder of the options the right to surrender his or her options for cancellation and receive a cash payment from the Company equal to the excess of the then current market price of the common shares over the exercise price of the options. To date, share appreciation rights have not been attached to stock options granted.

A separate share appreciation rights plan, where employees are granted the right to receive cash payments from the Company, but not common shares, was established in 2000. Under this plan, employees are entitled to cash payments equal to the excess of the then current market price of the common shares over the exercise price of the right. Other terms of the plan are similar to the employee stock option plan. During the year ended September 30, 2000, 1,738,101 rights at a weighted average exercise price of $22.09 were granted and, following employee departures, 95,040 rights at a weighted average price of $24.55 were cancelled. At September 30, 2000, 1,643,061 rights with exercise prices between $17.75 and $32.90 were outstanding and exercisable at various dates to 2005. At September 30, 2000, the weighted average exercise price of the rights was $21.95 and the weighted average remaining contractual life of the rights was 4.5 years. Compensation expense of $4.1 million has been recorded in the current year related to this plan.

Under the employee stock savings plan, the Company is authorized to issue shares of common stock to all of its permanent employees. Under the terms of the plan, qualifying employees may contribute from four percent to eight percent of basic annual earnings. Employee contributions are invested in the Company's common shares purchased from treasury at market prices. The Company matches the employees' contributions, investing in qualified money market instruments or additional common shares of the Company purchased on the open market. The Company's share of contributions is recorded as compensation expense and amounted to $4.1 million in 2000 (1999 – $3.5 million). At September 30, 2000, 859,565 common shares were reserved for issuance under the plan.

On November 16, 1999, the Board of Directors approved a Notice of Intention to make a Normal Course Issuer Bid, under which the Company could acquire up to five percent of its outstanding common shares through the facilities of The Toronto Stock Exchange. During the year, the Company repurchased 2.3 million shares at an average price of $16.81 per share. The repurchased shares were cancelled and returned to treasury.

On August 18, 1999, the Board of Directors adopted a Shareholder Rights Plan to replace the Company's previous plan which expired in 1999. The Plan was approved by shareholders on February 16, 2000. If a bid to acquire control of the Company is made, the Plan is designed to give the Board of Directors of the Company time to consider alternatives to allow shareholders to receive full and fair value for their shares. In the event that a bid, other than a permitted bid, is made, shareholders become entitled to exercise rights to acquire common shares of the Company at 50 percent of market value. This would significantly dilute the value of the bidder's holdings.

7. PER SHARE AMOUNTS

The Canadian Institute of Chartered Accountants has approved a new standard for the computation, presentation and disclosure of earnings per share. In the fourth quarter of fiscal 2000, the Company retroactively adopted the new standard. Under the new standard, the treasury stock method is used instead of the imputed earnings method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

In computing diluted earnings and cash flow from operations per share, 1.9 million shares were added to the weighted average number of common shares outstanding during the year ended September 30, 2000 (1999 – 0.4 million shares) for the dilutive effect of employee stock options. No adjustments were required to reported earnings or cash flow from operations in computing diluted per share amounts.

Prior period diluted earnings per share and cash flow from operations per share have been restated for this change. If the imputed earnings method had been used to calculate these amounts, the reported amounts would have been:

	2000	1999
Diluted earnings per common share		
From continuing operations	**$ 1.87**	$ 0.53
From discontinued operations	**0.49**	0.03
	$ 2.36	$ 0.56
Diluted cash flow from operations per common share		
From continuing operations	**$ 5.96**	$ 2.97
From discontinued operations	**0.03**	0.06
	$ 5.99	$ 3.03

8. TAXES

The provision for taxes differs from the result which would have been obtained by applying the combined federal and provincial tax rate to earnings before taxes. The difference results from the following items:

	2000	1999
Earnings from continuing operations before taxes	$ 474.1	$ 129.0
Combined federal and provincial tax rate	44.8%	44.8%
Computed "expected" tax	$ 212.4	$ 57.8
Increase (decrease) in taxes resulting from:		
Royalties and other payments to provincial governments	116.4	49.5
Non-deductible depletion	6.4	1.2
Resource allowance	(111.9)	(49.7)
Income tax rebates and credits	(7.6)	(2.1)
Capital taxes	10.3	7.0
Other	(0.1)	(1.1)
Provision for taxes	$ 225.9	$ 62.6

Property, plant and equipment with a net book value of $435.7 million (1999 – $33.1 million) has no cost base for income tax purposes.

9. CHANGE IN NON-CASH WORKING CAPITAL

	2000	1999
Accounts receivable	$ (102.7)	$ (23.6)
Inventories	(6.7)	(1.4)
Accounts payable and accrued liabilities	136.7	35.9
Taxes payable	(11.1)	13.4
Acquisition of non-cash working capital deficiency	(34.9)	–
Disposition of non-cash working capital deficiency	(0.2)	–
	$ (18.9)	$ 24.3

The following cash receipts (payments) have been included in the determination of earnings from continuing operations:

	2000	1999
Dividends received	$ 1.0	$ 1.1
Interest paid	$ (54.1)	$ (42.2)
Taxes paid	$ (19.0)	$ (7.3)

10. PENSION PLANS

The Company has a non-contributory registered defined benefit pension plan. In June 1995, the plan was amended to give active employees an opportunity to opt out of the plan in favour of a defined contribution alternative. Most employees opted out of the plan. These employees and all new employees accrue future benefits based on defined contributions. Employees remaining in the plan continue to accrue benefits under the defined benefit plan. The plan is funded based on independent actuarial valuations. Plan assets are invested primarily in treasury bills and/or publicly traded equity and fixed income securities. Retirement benefits are based on the employees' years of credited service and salaries during the last years of employment.

The retirement benefit under the registered plan is subject to a maximum pension as determined under the Income Tax Act (Canada). To the extent this limitation applied, supplemental retirement allowances were provided to qualifying employees at the time so that the total retirement benefits were sufficient to provide the annuity that those employees would have been entitled to without the limitation. To support the Company's obligations under the supplemental plan, the Company has issued a letter of credit to the custodian of the supplemental plan.

In August 1997, the Company purchased annuity contracts in respect of all the then retired and deferred vested members of the registered plan. Pension assets were used to purchase the annuities. Projected benefit obligations were reduced to reflect this purchase of annuities.

Based on an actuarial valuation dated September 30, 2000, the status of the plans on that date was:

	2000	1999
Pension plan assets	$ 21.0	$ 20.3
Projected benefit obligations	(9.0)	(8.8)
Excess of pension plan assets over projected benefit obligations	$ 12.0	$ 11.5

In 2000, the Company recorded pension expense of $0.4 million (1999 – $0.4 million).

On October 6, 2000, a benefit enhancement of approximately $8.3 million was granted to those retired and deferred vested members of the registered plan as of December 31, 2000 for whom annuities were purchased in 1997. Pension plan assets were reduced by this amount subsequent to September 30, 2000.

11. FINANCIAL INSTRUMENTS

(a) INTEREST RATE RISK

The Company has entered into fixed rate debt agreements and interest rate swap agreements in order to manage its interest rate exposure on debt instruments. These agreements are described in note 4.

(b) FOREIGN CURRENCY EXCHANGE RISK

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices.

(c) CREDIT RISK

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

The Company is also exposed to credit risk associated with possible non-performance by counterparties to the interest rate swap agreements. The Company believes these risks to be minimal as the counterparties are major financial institutions which have at least an AA credit rating as determined by recognized credit rating agencies.

(d) FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts of financial instruments included in the consolidated balance sheet, other than long term debt, approximate their fair value due to their short term maturity.

The estimated fair values of long term debt and derivative instruments have been determined based on discounted cash flow analysis using current market interest rates for financial instruments with similar maturities.

The carrying values and estimated fair values of long term debt and derivative instruments are as follows:

	2000		1999	
	Carrying value	Fair value	Carrying value	Fair value
Continuing operations				
Bank loans	$ 638.9	$ 638.9	$ 280.2	$ 280.2
Interest rate swaps on bank loans	$ –	$ 2.2	$ –	$ 2.4
Medium term notes	$ 175.0	$ 177.2	$ –	$ –
Senior U.S. dollar notes	$ 113.0	$ 112.6	$ –	$ –
Oil indexed debentures	$ 200.0	$ 200.0	$ 200.0	$ 199.3
Interest rate swap on oil indexed debentures	$ –	$ –	$ –	$ 6.2
Discontinued operations (note 2)				
Bank loans	$ –	$ –	$ 55.1	$ 55.1
9.54% sinking fund debentures	$ –	$ –	$ 10.8	$ 11.6

12. COMMITMENTS

In 1999 and 2000, the Company acquired interests in northern Canada for total work expenditure proposals of $376.7 million. Work expenditures commenced in fiscal 2000, with $4.6 million of eligible expenditures incurred. Expenditures will continue over the next five years and include the requirement to drill at least one well on each licence or permit. The proposals are supported by deposits of $85.0 million in letters of credit. The letters of credit will be reduced proportionately as eligible expenditures are incurred.

FINANCIAL (in millions, except per share amounts)	2000	1999	1998	1997
Revenues				
Oil and gas	$ 1,417.1	$ 770.9	$ 655.9	$ 722.2
Royalties, net of ARTC	(291.8)	(125.9)	(107.7)	(120.4)
	1,125.3	645.0	548.2	601.8
Expenses				
Operating	209.4	153.6	160.5	147.8
Depletion and depreciation	312.0	260.7	252.8	237.5
General and administrative	52.9	40.7	31.6	28.7
Interest	58.3	42.5	44.0	34.8
Future site restoration	18.6	18.5	11.7	10.2
Restructuring costs	–	–	–	–
	651.2	516.0	500.6	459.0
Earnings (loss) from continuing operations before taxes	474.1	129.0	47.6	142.8
Taxes				
Current	7.8	20.5	6.7	2.1
Deferred	218.1	42.1	23.0	60.4
	225.9	62.6	29.7	62.5
Earnings (loss) from continuing operations	248.2	66.4	17.9	80.3
Earnings from discontinued operations	65.3	4.0	6.7	7.6
Earnings (loss)	$ 313.5	$ 70.4	$ 24.6	$ 87.9
Basic earnings (loss) per common share				
From continuing operations	$ 1.95	$ 0.54	$ 0.15	$ 0.66
From discontinued operations	0.51	0.03	0.05	0.06
	$ 2.46	$ 0.57	$ 0.20	$ 0.72
Cash flow from operations				
From continuing operations	$ 796.9	$ 387.6	$ 296.3	$ 372.7
From discontinued operations	4.4	8.0	9.7	10.3
	$ 801.3	$ 395.6	$ 306.0	$ 383.0
Basic cash flow from operations per common share				
From continuing operations	$ 6.26	$ 3.13	$ 2.41	$ 3.06
From discontinued operations	0.03	0.06	0.08	0.08
	$ 6.29	$ 3.19	$ 2.49	$ 3.14
Balance sheet information				
Net oil and gas capital expenditures	$ 669.4	$ 283.8	$ 476.2	$ 448.9
Corporate oil and gas acquisitions (dispositions)	$ 1,000.7	$ –	$ –	$ (50.4)
Long term debt	$ 1,126.9	$ 545.2	$ 695.5	$ 545.0
Working capital (deficiency)	$ (63.0)	$ (29.9)	$ (11.9)	$ (7.7)
Shareholders' equity	$ 1,563.5	$ 1,135.8	$ 1,022.7	$ 986.1
Common shares outstanding at September 30	131.5	126.0	123.3	122.4

OPERATING				
Daily sales				
Natural gas (Mmcfd)	626	568	555	549
Crude oil (Bpd)	29,026	25,565	29,808	27,472
NGL (Bpd)	11,379	8,020	7,376	5,669
	40,405	33,585	37,184	33,141
Proven reserves				
Natural gas (Bcf)	2,231	1,812	1,758	1,768
Crude oil and NGL (Mmbbls)	190.9	146.0	148.0	130.9
Proven plus probable reserves				
Natural gas (Bcf)	3,239	2,699	2,675	2,713
Crude oil and NGL (Mmbbls)	273.9	221.7	225.6	200.3
Wells drilled for oil and gas				
Gross	630	273	446	669
Net	469	179	280	426
Employees				
Calgary	467	410	390	347
Field	387	352	347	332
Total	854	762	737	679

* In September 1995, a business combination between Anderson Exploration Ltd. and Home Oil Company Limited was accomplished. The business combination was accounted for using the pooling of interests method of accounting. Under this method, the consolidated financial and operating results reflect the historical results of both companies as if they had always been together. This means that the pooled financial and operating results for fiscal

1996	1995 (pooled)*	1995*	1994*	1993*	1992*	1991*
$ 572.7	$ 518.7	$ 230.0	$ 209.1	$ 136.7	$ 94.8	$ 93.6
(92.6)	(85.6)	(39.2)	(42.9)	(26.1)	(18.1)	(20.8)
480.1	433.1	190.8	166.2	110.6	76.7	72.8
108.0	102.3	42.1	35.2	24.4	20.5	18.6
216.2	205.4	93.2	66.7	42.7	30.5	23.7
26.4	48.3	9.8	8.0	6.2	5.6	4.6
39.8	47.7	13.7	8.3	10.0	10.8	8.3
9.8	8.3	4.4	3.3	2.0	1.5	–
–	36.0	4.1	–	–	–	–
400.2	448.0	167.3	121.5	85.3	68.9	55.2
79.9	(14.9)	23.5	44.7	25.3	7.8	17.6
5.6	2.7	2.2	1.9	0.9	0.8	5.0
33.9	(3.0)	9.6	18.6	9.4	3.8	6.6
39.5	(0.3)	11.8	20.5	10.3	4.6	11.6
40.4	(14.6)	11.7	24.2	15.0	3.2	6.0
7.8	8.8	–	–	–	–	–
$ 48.2	$ (5.8)	$ 11.7	$ 24.2	$ 15.0	$ 3.2	$ 6.0
$ 0.33	$ (0.12)	$ 0.21	$ 0.45	$ 0.33	$ 0.08	$ 0.15
0.07	0.07	–	–	–	–	–
$ 0.40	$ (0.05)	$ 0.21	$ 0.45	$ 0.33	$ 0.08	$ 0.15
$ 295.9	$ 199.9	$ 119.0	$ 112.8	$ 69.0	$ 39.1	$ 36.3
10.9	8.4	–	–	–	–	–
$ 306.8	$ 208.3	$ 119.0	$ 112.8	$ 69.0	$ 39.1	$ 36.3
$ 2.45	$ 1.66	$ 2.09	$ 2.09	$ 1.52	$ 0.95	$ 0.89
0.09	0.07	–	–	–	–	–
$ 2.54	$ 1.73	$ 2.09	$ 2.09	$ 1.52	$ 0.95	$ 0.89
$ 245.9	$ 321.9	$ 175.6	$ 178.9	$ 81.6	$ 12.5	$ 33.0
$ –	$ –	$ –	$ 70.0	$ –	$ 106.5	$ –
$ 512.7	$ 561.9	$ 153.3	$ 90.5	$ 90.8	$ 152.2	$ 72.7
$ (13.8)	$ (20.2)	$ (12.3)	$ (18.0)	$ (11.4)	$ 1.5	$ 1.6
$ 881.3	$ 828.0	$ 421.5	$ 410.7	$ 276.1	$ 196.3	$ 191.8
121.0	120.5	57.2	56.9	49.4	41.4	41.2

506	507	282	215	160	111	77
24,097	25,628	8,606	6,510	4,775	4,131	4,346
5,489	6,253	2,040	1,746	1,182	1,617	1,082
29,586	31,881	10,646	8,256	5,957	5,748	5,428
1,798	1,812	901	900	755	698	619
107.7	99.2	30.4	29.4	19.4	17.7	15.1
2,694	2,739	1,387	1,378	1,162	1,033	907
165.7	158.9	46.7	43.9	28.4	25.4	22.3
335	308	136	225	157	43	73
210	230	105	172	90	21	54
293	314	105	106	79	65	53
329	347	119	110	79	67	61
622	661	224	216	158	132	114

1995 reflect the combined operations of the two companies for that entire year even though the business combination was only accomplished in the last month of the year. Fiscal 2000 is the fifth full year after the business combination. Historical results of Anderson Exploration Ltd. on a stand alone basis have been provided as supplementary information for 1995 and prior years.

OIL AND GAS OPERATIONS	Gas Converted to Oil at 6 Mcf/Bbl*			Gas Converted to Oil at 10 Mcf/Bbl*		
	2000	1999	1998	**2000**	1999	1998
Cash flow from operations and earnings per barrel of oil equivalent						
Oil and gas revenues	**$ 26.74**	$ 16.47	$ 13.68	**$ 37.57**	$ 23.37	$ 19.12
Royalties	**(5.51)**	(2.69)	(2.28)	**(7.74)**	(3.82)	(3.18)
Operating costs	**(3.95)**	(3.28)	(3.39)	**(5.55)**	(4.66)	(4.75)
	17.28	10.50	8.01	**24.28**	14.89	11.19
General and administrative expenses	**(1.00)**	(0.87)	(0.67)	**(1.40)**	(1.23)	(0.93)
Interest	**(1.10)**	(0.91)	(0.93)	**(1.55)**	(1.29)	(1.30)
Current taxes	**(0.15)**	(0.44)	(0.14)	**(0.21)**	(0.62)	(0.20)
Cash flow from operations	**15.03**	8.28	6.27	**21.12**	11.75	8.76
Depletion and depreciation	**(5.89)**	(5.57)	(5.35)	**(8.27)**	(7.90)	(7.48)
Future site restoration	**(0.35)**	(0.39)	(0.25)	**(0.49)**	(0.56)	(0.35)
Deferred taxes	**(4.11)**	(0.90)	(0.49)	**(5.78)**	(1.28)	(0.68)
Other	**–**	–	0.19	**–**	–	0.28
Earnings	**$ 4.68**	$ 1.42	$ 0.37	**$ 6.58**	$ 2.01	$ 0.53
Average daily sales in barrels of oil equivalent	**144,809**	128,209	129,599	**103,047**	90,360	92,634
Natural Gas and NGL Netbacks						
Sales revenue ($/Mcf)	**$ 3.93**	$ 2.49	$ 2.00	**$ 3.69**	$ 2.37	$ 1.91
Royalties ($/Mcf)	**(0.84)**	(0.43)	(0.35)	**(0.79)**	(0.41)	(0.34)
Operating costs ($/Mcf)	**(0.50)**	(0.43)	(0.37)	**(0.47)**	(0.41)	(0.35)
Cash netback ($/Mcf)	**$ 2.59**	$ 1.63	$ 1.28	**$ 2.43**	$ 1.55	$ 1.22
Average daily natural gas sales (Mmcfd)	**626**	568	555	**626**	568	555
Average daily NGL sales (Bpd)	**11,379**	8,020	7,376	**11,379**	8,020	7,376
Crude Oil Netbacks						
Sales revenue ($/Bbl)	**$ 37.55**	$ 21.17	$ 18.57			
Royalties ($/Bbl)	**(7.25)**	(3.16)	(2.92)			
Operating costs ($/Bbl)	**(7.82)**	(5.97)	(7.26)			
Cash netback ($/Bbl)	**$ 22.48**	$ 12.04	$ 8.39			
Average daily crude oil sales (Bpd)	**29,026**	25,565	29,808			
Finding and Development Costs ($/Boe)						
Current year additions before revisions						
Proven	**$ 8.95**	$ 4.89	$ 6.80	**$ 12.12**	$ 7.62	$ 8.84
Proven plus one half probable	**$ 7.57**	$ 3.96	$ 5.74	**$ 10.33**	$ 6.15	$ 7.41
Current year additions after revisions						
Proven	**$ 9.84**	$ 5.31	$ 7.66	**$ 13.26**	$ 7.85	$ 9.62
Proven plus one half probable	**$ 9.09**	$ 5.66	$ 7.44	**$ 12.29**	$ 8.40	$ 9.12
Three year weighted average after revisions						
Proven	**$ 8.50**	$ 6.50	$ 6.47	**$ 11.46**	$ 8.45	$ 8.13
Proven plus one half probable	**$ 8.15**	$ 6.22	$ 6.18	**$ 10.94**	$ 7.96	$ 7.66
Five year weighted average after revisions						
Proven	**$ 7.74**	$ 5.72		**$ 10.23**	$ 7.69	
Proven plus one half probable	**$ 7.39**	$ 5.03		**$ 9.71**	$ 6.71	

* The operating statistics presented in this analysis are expressed on a barrel of oil equivalent basis (or thousand cubic feet equivalent basis) using two different ratios. Previously in Canada, it was common to convert gas to oil at 10 thousand cubic feet per barrel, which approximated historical relative sales values. Outside of Canada, particularly in the United States, it was more common to convert gas to oil at six thousand cubic feet per barrel, which approximates relative heating values. With improved access to U.S. gas markets and the resulting improvements to gas prices, more Canadian oil and gas companies and analysts in the investment community are adopting the 6:1 ratio. Anderson Exploration has adopted the 6:1 ratio throughout this annual report and provides information using the 10:1 ratio in the table above as supplementary information.

QUARTERLY INFORMATION

(in millions, except per share amounts)	Year ended September 30, 2000 Q1	Q2	Q3	Q4	Total
Oil and gas revenue before royalties	$ 266.1	$ 277.1	$ 382.7	$ 491.2	$1,417.1
Cash flow from operations					
From continuing operations	$ 148.3	$ 152.9	$ 218.6	$ 277.1	$ 796.9
From discontinued operations	$ 1.3	$ 3.1	$ –	$ –	$ 4.4
	$ 149.6	$ 156.0	$ 218.6	$ 277.1	$ 801.3
Basic cash flow from operations per common share*					
From continuing operations	$ 1.18	$ 1.23	$ 1.71	$ 2.11	$ 6.26
From discontinued operations	$ 0.01	$ 0.02	$ –	$ –	$ 0.03
	$ 1.19	$ 1.25	$ 1.71	$ 2.11	$ 6.29
Earnings					
From continuing operations	$ 44.0	$ 44.4	$ 68.1	$ 91.7	$ 248.2
From discontinued operations	$ (0.1)	$ 1.9	$ 63.5	$ –	$ 65.3
	$ 43.9	$ 46.3	$ 131.6	$ 91.7	$ 313.5
Basic earnings per common share*					
From continuing operations	$ 0.35	$ 0.36	$ 0.53	$ 0.70	$ 1.95
From discontinued operations	$ –	$ 0.01	$ 0.50	$ –	$ 0.51
	$ 0.35	$ 0.37	$ 1.03	$ 0.70	$ 2.46
Net oil and gas capital expenditures	$ 158.0	$ 218.9	$ 117.3	$ 175.2	$ 669.4
Daily sales					
Gas (Mmcfd)	572	562	668	703	626
Light/medium crude oil (Bpd)	21,813	22,333	23,803	26,723	23,672
Heavy crude oil (Bpd)	4,010	5,379	5,806	6,228	5,354
Total crude oil (Bpd)	25,823	27,712	29,609	32,951	29,026
NGL (Bpd)	9,514	9,740	12,571	13,684	11,379
Total liquids (Bpd)	35,337	37,452	42,180	46,635	40,405

(in millions, except per share amounts)	Year ended September 30, 1999 Q1	Q2	Q3	Q4	Total
Oil and gas revenue before royalties	$ 176.3	$ 174.3	$ 188.2	$ 232.1	$ 770.9
Cash flow from operations					
From continuing operations	$ 91.2	$ 82.9	$ 93.6	$ 119.9	$ 387.6
From discontinued operations	$ 1.2	$ 2.0	$ 2.1	$ 2.7	$ 8.0
	$ 92.4	$ 84.9	$ 95.7	$ 122.6	$ 395.6
Basic cash flow from operations per common share					
From continuing operations	$ 0.74	$ 0.67	$ 0.76	$ 0.96	$ 3.13
From discontinued operations	$ 0.01	$ 0.02	$ 0.01	$ 0.02	$ 0.06
	$ 0.75	$ 0.69	$ 0.77	$ 0.98	$ 3.19
Earnings					
From continuing operations	$ 12.4	$ 9.3	$ 15.8	$ 28.9	$ 66.4
From discontinued operations	$ 0.5	$ 1.2	$ 1.2	$ 1.1	$ 4.0
	$ 12.9	$ 10.5	$ 17.0	$ 30.0	$ 70.4
Basic earnings per common share					
From continuing operations	$ 0.10	$ 0.08	$ 0.13	$ 0.23	$ 0.54
From discontinued operations	$ –	$ 0.01	$ 0.01	$ 0.01	$ 0.03
	$ 0.10	$ 0.09	$ 0.14	$ 0.24	$ 0.57
Net oil and gas capital expenditures	$ 73.4	$ 101.3	$ 25.8	$ 83.3	$ 283.8
Daily sales					
Gas (Mmcfd)	559	558	570	584	568
Light/medium crude oil (Bpd)	24,161	23,433	22,156	21,616	22,840
Heavy crude oil (Bpd)	2,516	2,510	2,753	3,117	2,725
Total crude oil (Bpd)	26,677	25,943	24,909	24,733	25,565
NGL (Bpd)	8,241	8,837	6,774	8,232	8,020
Total liquids (Bpd)	34,918	34,780	31,683	32,965	33,585

* The sum of the quarterly per share amounts does not equal the annual per share amount due to the different weightings of shares issued during the year.

CORPORATE INFORMATION

BOARD OF DIRECTORS

J.C. Anderson
(1968)
Chairman & Chief Executive Officer
Calgary, Alberta

Ian D. Bayer (1)
(1984)
Corporate Director
North York, Ontario

W. Gordon Brown, Q.C. (2)(3)
(1982)
Partner
Bennett Jones
Calgary, Alberta

Thomas N. Davidson (1)(4)
(2000)
Chairman
Quarry Hill Group
Key Largo, Florida

E. Susan Evans, Q.C. (1)(4)
(1995)
Corporate Director
Calgary, Alberta

J. Richard Harris (2)(3)
(1988)
Oil & Gas Consultant
Calgary, Alberta

Charles J. Howard (1)(4)
(1993)
President & Chief Executive Officer
Ausnoram Holdings Limited
Oakville, Ontario

R.T. (Tim) Swinton (2)(3)
(2000)
Executive Chairman
IPEC Ltd.
Calgary, Alberta

(1) Member of Audit Committee
(2) Member of Compensation Committee
(3) Member of Reserves Committee
(4) Member of Governance Committee
(Fiscal year first elected as Director)

CORPORATE OFFICERS

J.C. Anderson
Chairman & Chief Executive Officer

Brian H. Dau
President & Chief Operating Officer

David G. Scobie
Senior Vice President &
Chief Financial Officer
Treasurer

Henry H. Assen
Vice President, Marketing

Fred E. Baker
Vice President, Exploration

Phil A. Harvey
Vice President, Exploitation

Dan F. Kell
Vice President, Land

W. A. (Drew) Livingston
Vice President, Production

Kevin L. Stashin
Vice President, Operations

Gerry S. Read
Controller

R. Vance Milligan
Partner, Bennett Jones
Secretary

MANAGERS

Business Development

Department Head
David M. Spyker

Exploration

Area Managers
Steve J. Babcock
Frank J. Gratton
Ron A. Lambie
James W. Muraro
Al J. Onia
H. Brent Snyder
Tim B. Watters

Geophysical Operations
Ken B. Robinson

Geo-Technical Services
Graeme R. Bloy

Exploitation

Area Managers
Scot Collins
Brian G. Kergan
Greg J. Kuran
Paul E. Vigneau
Cal R. Watson
Will N. Yakymyshyn

Finance

Finance
M. Darlene Wong

Office Services
Linda M. Ellergodt

Operations Accounting
George R. Nichols

Land

Land & Contract Administration
Lynn M. Gregory

Land Negotiations
Sandy M. Drinnan

Marketing

Natural Gas
Keith J. Fardy

Liquids
Josie M. MacGillivray

Operations

Drilling
Carl F. Hiscock

Completions
Jim N. Peta

Production Engineering
Pat G. Bell
Phil G. Hyde
Tom J. Negenman

Production

Facilities
Doug N. Whiteside

Production
Jan H. Olthof

Safety & Environment
Walter C. Tersmette

District Superintendents

Carstairs, Alberta
Terry J. Clelland

Fairview, Alberta
Ron L. Strandquist

Fort St. John, British Columbia
Tip C. Johnson

Lloydminster, Alberta
Doug J. Moore

Swan Hills, Alberta
Bill N. Crossman

Wapiti, Alberta
Rob M. Petrone

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FIELD OFFICES

Carstairs, Alberta
Fairview, Alberta
Fort St. John, British Columbia
Lloydminster, Alberta
Swan Hills, Alberta
Wapiti, Alberta

AUDITORS

KPMG LLP
Calgary, Alberta

SOLICITORS

Bennett Jones LLP
Calgary, Alberta

INDEPENDENT ENGINEERS

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

REGISTRAR & TRANSFER AGENT

Computershare
(on behalf of Montreal Trust Company of Canada)
Calgary, Vancouver, Winnipeg, Toronto, Montreal, Halifax

STOCK EXCHANGE

The Toronto Stock Exchange
Symbol: AXL

ANNUAL INFORMATION FORM

Copies of the Company's Annual Information Form are available on request.

CORPORATE GOVERNANCE

Information concerning the Company's corporate governance is presented in the Notice of and Information Circular for the Annual and Special Meeting of Shareholders dated January 3, 2001.

VOLUME REPORTING

All production, sales and reserve statistics are Anderson Exploration's working interest amounts before deduction of royalties, unless stated otherwise. Where volumes are reported in barrels of oil equivalent, gas is converted to oil at six thousand cubic feet per barrel, unless stated otherwise. Many key financial and operating statistics have also been calculated using ten thousand cubic feet per barrel and are provided as supplementary information on page 66 of this annual report.

FINANCIAL REPORTING

All amounts are in Canadian dollars, unless stated otherwise. The Company's fiscal year end is September 30.

ABBREVIATIONS USED IN ANNUAL REPORT

Bbl	barrel(s)
Bcf	billion cubic feet
Bpd	barrels per day
Boe	barrels of oil equivalent
Mbbls	thousand barrels
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day
Mmbbls	million barrels
Mmcfd	million cubic feet per day
NGL	natural gas liquids

Anderson Exploration's Senior Management Team (from left to right): J.C. Anderson, Drew Livingston, Kevin Stashin, David Spyker, Dan Kell, Brian Dau, David Scobie, Fred Baker, Henry Assen, Phil Harvey.

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